United States
Department of
Agriculture

Forest
Service

February 2012

Final Environmental Impact Statement

South Unit Oil and Gas Development Project

Duchesne/Roosevelt Ranger District, Ashley National Forest
Duchesne County, Utah

South Unit Oil and Gas Development Project
Final Environmental Impact Statement
Duchesne County, Utah
(Volume 2 of 2)

Lead Agency:	**USDA Forest Service**
Cooperating Agencies:	**State of Utah, Governor's Public Lands Policy Coordination Office** **U.S.D.I. Bureau of Land Management**
Responsible Official:	**Kevin B. Elliott, Forest Supervisor** **355 North Vernal Avenue** **Vernal, Utah 84078**
For Information Contact:	**David Herron, Project Lead** **85 West Main, P.O. Box 981** **Duchesne, Utah 84021** **435-781-5218**

Abstract: Berry Petroleum Company has submitted a Master Development Plan (MDP) to explore and develop oil and gas reserves in the South Unit of the Ashley National Forest in Duchesne County, Utah. This MDP is defined as the Proposed Action within this Final Environmental Impact Statement (FEIS). Berry proposed to drill as many as 400 new wells within the Project Area, which represents a full development scenario. Of these 400 wells, 44 have already been approved for drilling under separate, site-specific NEPA analysis. The Project Area includes approximately 25,900 acres and is located 11 miles south of Duchesne, Utah, in Township 6 South, Ranges 4 and 5 West.

Alternatives to the Proposed Action considered are:

- no action alternative;
- phased development, which would allow for up to 356 new wells drilled in phases according to wildlife range seasonal restrictions and subject to slope stipulation; and
- use of directional drilling and multiple wells per well pad to minimize the total disturbance by minimizing the number of well pads and access roads required compared to the Proposed Action. Allow up to 400 wells using a combination of new and existing wells, drilled from a maximum of 162 well pads at an average spacing of four well pads per section.

Table of Contents

United States
Department of
Agriculture

Forest
Service

February 2010

Appendix A
Ashley National Forest
Master Development Plan

South Unit Oil and Gas Development
Draft Environmental Impact Statement

Duchesne Ranger District, Ashley National Forest
Duchesne County, Utah

Berry Petroleum Company

Full Field Oil and Gas Exploration and Development Project
Master Development Plan
Ashley National Forest, South Unit

For lands in the following sections:
T6S-R5W: Sections 1 - 18, 21, 22, 24, 25
T6S-R4W: Sections 1 - 17, 21, 22
Duchesne County, Utah

Including:

13 Point Surface Use Plan (Appendix 1)

This page intentionally left blank.

PROPOSED ACTION

Introduction

Berry Petroleum Company (Berry) is proposing to drill up to 400 oil and gas wells on federal mineral leases the Company holds under the South Unit of the Ashley National Forest in Duchesne County, Utah. The purpose of the project is to explore for economically recoverable deposits of crude oil and/or natural gas and to produce those resources for delivery to market. The proposed Project Area is defined as Berry's current lease holdings within the South Unit of the Ashley National Forest, which cover an area of roughly 40.5 square miles (25,900 acres). This Project Area begins approximately 11 miles south of the town of Duchesne, Utah. Figure 1 provides a map of Berry's proposed Project Area.

This Master Development Plan (MDP) is intended to provide a conceptual description of an overall exploration and development scenario instead of a case-by-case submittal of Applications for Permit to Drill (APDs) on individual wells. The intent of the MDP process is to address environmental impacts associated with oil and gas development within a defined geographic area. In addition, the MDP process was created to propose mitigation measures for potential impacts to environmental resources, such as wildlife habitat, water resources, and visual resources that may occur within distinct locations and ecosystems. The Proposed Action was designed to be fully compliant with the stipulations identified in Berry's federal mineral leases and consistent with the forest planning decisions embodied in the Western Uintah Basin Oil and Gas Leasing EIS, 1997 and Record of Decision. The Western Uintah Basin Oil and Gas Leasing EIS amended the Ashley National Forest Plan to include the leasing of federal oil and gas resources and subsequent development of oil and gas wells on Forest Service-administered lands.

The MDP is a projected development scenario proposed by Berry Petroleum Company given current market conditions and demand for oil and gas, other constraints on the company, by environmental constraints embodied within the company's oil and gas lease stipulations, and additional mitigation measures imposed by the Forest Service. The major elements of the MDP are organized below in three sections: 1) Development (Construction/Drilling/Completion), 2) Production (Operation and Maintenance), and 3) Reclamation. In addition, the proposed Surface Use Plan for the Proposed Action is contained in Appendix 1.

Development (Pad and Road Construction, Well Drilling and Completion)

As described previously, Berry proposes to drill up to 400 oil and gas wells within the Project Area during a 5- to 20-year program beginning in 2008 or 2009. All of the proposed wells would be drilled on existing federal mineral leases held by Berry. The proposed locations and spacing of wells would be consistent with State of Utah spacing rules. In general, in the northern portion of the Project Area, where economic quantities of oil and gas are more likely to be present, wells would be drilled on approximately 40-acre spacing. In the southern portion of the Project Area, the potential for occurrence of economic quantities of oil and gas is generally believed to be lower and a more exploratory spacing of approximately 160-acres is envisioned. The actual spacing and geographic distribution of wells over the life of the project would be based on actual discoveries of economic quantities of oil and gas resources.

Berry expects to drill all of the proposed wells from 2008 or 2009 through 2027 or 2028. It is possible that the Company could drill fewer than 400 wells because of geologic and market uncertainties. The MDP is conceptual in nature and provides a maximum development scenario, assuming oil and gas is found in economic quantities throughout the Project Area. As of January

1, 2007, Berry is operating two wells within the Project Area boundary. Those wells are both producing economic quantities of oil and gas at present.

The proposed oil and gas wells would be drilled from well pads constructed of native soil and rock material using standard cut and fill methods. At the beginning of pad construction, surface soils would be salvaged and stockpiled adjacent to the well pad site for future use in site reclamation. The well pads and their associated reserve pits would then be constructed using heavy equipment. Berry estimates that approximately 2.5 acres of surface terrain would be disturbed to create each well pad. The amount of surface disturbance at each well pad would vary on a site-by-site basis depending on topography.

Cut slopes required for pad construction would not be steeper than 1.5:1. In some cases, additional engineering measures would be implemented to construct drainage systems and culverts in order to divert water flow away from the well pads and roads, prevent erosion, and prevent sediment loading in creek channels due to construction. These locations and engineered designs would be submitted with the site-specific APDs.

The proposed oil and gas wells would be drilled to an average depth of about 6,000 feet. The typical oil and gas well in this MDP would require about 7 days to drill, 14 days to complete, with an additional 7 days or so for production equipment installation and well start up (about 28 days from spud to production). All cuttings and drilling fluids would be contained in the reserve pit. All pits, cellars, rat holes, and other bore holes unnecessary for oil and gas production, excluding the reserve pit, would be backfilled after the drill rig is released to conform to the surrounding terrain.

Drilling fluids/mud and produced water would be contained within reserve pits excavated on each of the well pads. The reserve pits would be lined with a synthetic reinforced liner a minimum of 12 millimeters thick, with sufficient bedding used to cover any rocks. The liner would overlap the pit walls and be covered with dirt and/or rocks to hold it in place. Trash or scrap that could puncture the liner would not be disposed of in the pits. A minimum of two feet of free board would be maintained in the reserve pit, between the maximum fluid level and the top of the pit berm. These pits would be designed to exclude all surface runoff. The reserve pits would be drained and emptied of fluids within 90 days of well completion as stated in Onshore Order #7. The backfilling of the reserve pit would be done in such a manner that the mud and associated solids would be confined to the pit and not squeezed out and incorporated in the surface materials. There would be a minimum of three feet of cover (overburden) on the pit. When work is complete, the pit area would support the weight of heavy equipment without sinking. Following backfilling, the reserve pit area would be covered with a portion of the stockpiled soil and seeded with native vegetation as directed by the Forest Service.

Approximately 100 miles of new access roads and 21 miles of upgraded existing roads would be constructed to reach the proposed well pad sites. These roads would utilize a construction right-of-way (ROW) 35 feet wide during construction. After construction is complete and gas gathering lines are installed, approximately 13 feet would be rehabilitated leaving a 22-foot road surface.

The Project would include approximately 130 miles of gas gathering pipelines. Low pressure lines would be poly pipe installed on the surface. High pressure lines would be made of steel and buried. Gas gathering pipelines would parallel access roads in the vast majority of cases and add virtually no additional surface disturbance as they would utilize the 35-foot road ROW. In some locations, surface pipelines would drop off of ridgelines to the valleys below. In total, approximately 130 miles of gas gathering pipelines would be required for this project. Berry anticipates the Project would require about 10,000 HP of compression at 4 compressor stations that would be located within or near the Project Area.

Production (Operation and Maintenance)

A typical Berry well location would consist of one or two wellheads, a pump jack(s), and two 400-barrel capacity above ground crude oil tanks per well. The pump jacks would be driven by natural gas or propane-fired internal combustion engines equipped with high-quality noise-reducing mufflers. Production equipment would be painted to match the surrounding terrain and minimize visual impact. Emergency shut down equipment would be employed to minimize the risk of spills. Crude oil would be hauled away by truck. On average, Berry estimates 1 truck trip would be required every 8 days per well to haul crude oil offsite to market. Gathered natural gas would be dehydrated and compressed at up to 4 new compressor stations within or adjacent to the Project Area. If production requirements make onsite compression necessary, a Sundry Notice (Form 3160) would be submitted for approval to the Authorized Officer detailing specifications prior to installation of compressors.

Produced water would be decanted from the crude oil tanks into an external steel tank installed within secondary containment next to the crude oil tanks and pumped periodically as needed. Produced water at the well pads would be transported by tanker trucks to approved disposal sites or reused for drilling at other Berry locations.

After completion activities, Berry would reduce the size of the well pad to the minimum surface area needed for production facilities including adequate room for oil trucks to turn around, while providing for reshaping and stabilization of cut and fill slopes. The cut and fill slopes would be reshaped to mimic the adjacent natural terrain. Reclaimed portions of the pads would be seeded with native vegetation as directed by the Forest Service.

Periodically, a workover or recompletion of a well would be required to ensure that efficient production is maintained. Workovers can include repairs to the well bore equipment (casing, tubing, rods, or pump), the wellhead, or the production facilities. These repairs would usually be completed in several days per well, during daylight hours. The frequency for this type of work cannot be accurately projected because workovers vary by well; however, on average, one workover per well, per year is required after 5 years of production. Workovers typically take 7 days to complete. In the case of a recompletion, where casings are worked on or valves and fittings would be replaced to stimulate production, a temporary reserve pit may have to be constructed on the well pad.

Reclamation

At the end of its productive life, each well would be plugged, capped, and all surface equipment would be removed. All surface pipelines no longer in use would also be removed. Buried pipelines would be plugged at specified intervals and abandoned in place. Each well pad would then be recontoured to duplicate the adjacent natural topography using heavy equipment and previously salvaged soil material would be spread over the surface of the pad site. The reclaimed surface would then be reseeded with native vegetation; the seed mix would be determined by the Forest Service and would generally mimic native vegetation surrounding the specific well site. Well site reclamation would be performed and monitored in consultation with the Ashley National Forest, including the control of noxious weeds. Well site reclamation would be performed and monitored in accordance with the Standard Surface Use Plan (Appendix 1).

A Sundry Notice would be submitted by the operator to the BLM that describes the engineering, technical, or environmental aspects of final well plugging and abandonment. It would describe final reclamation procedures and any mitigation measures performed by the operator. The BLM and UDOGM standards for plugging would be followed. A configuration diagram, a summary of plugging procedures, and a job summary with techniques used to plug the well bore (e.g., cementation) would be included in the Sundry Notice.

Site-Specific Development Process

Following completion of the NEPA process for the proposed project envisioned in the MDP, Berry would begin the process of proposing site-specific well development. Well locations, associated roads and pipeline routes, and the location of ancillary facilities would be staked and surveyed and on-site inspections scheduled with Ashley National Forest personnel. The on-site inspections would be conducted by the Forest Service, proponent, and contractors to assess proposed well pad layout, road and pipeline routes, compressor sites, etc. The purpose of the on-site inspection would be to confirm that the proposed facility is consistent with the upcoming Full Field Oil and Gas Development EIS, applicable lease stipulations, Forest Plan requirements, and to generally avoid and/or minimize adverse environmental effects. Once the location is approved, required surveys for the presence or absence of sensitive plant and wildlife species, cultural and paleontological resources, and other applicable field surveys would take place as appropriate to confirm these resources would be avoided and/or impacts minimized.

Lease Stipulations and Proposed Design Elements to Minimize Environmental Effects

Within the proposed Project Area, Berry holds 17 federal oil and gas leases. Table 1-1 lists the leases and associated stipulations. In addition to the lease stipulations, Berry is also incorporating into this MDP various design elements and mitigation measures that were identified in the Decision Notice and Finding of No Significant Impact for the 2006 Environmental Assessment for Berry's Exploration and Development Project in the Ashley National Forest. These design elements and mitigation measures have been included within the Proposed Action in order to avoid or minimize potential adverse environmental effects. These measures are above and beyond those required by Berry's lease stipulations. A summary of the proposed design elements and mitigation measures are listed below:

Paleontology

- A qualified Paleontologist would monitor construction activities for proposed well pads and their access roads if shallow or exposed bedrock is present that is potentially fossil-bearing. If significant paleontological resources are discovered, construction activities would be halted and the Forest Service notified. Operations in the area of the discovery would not resume until authorization to proceed has been received from the Forest Service.

Soil and Water Resources

- To prevent erosion of disturbed soils, vegetation and/or structural measures to control erosion would be implemented as soon as possible after initial soil disturbance.
- Energy dissipaters such as straw bales and silt fences may be required to prevent excess erosion of soils from disturbed areas into adjacent stream channels or floodplains. These structures would be installed during construction, and would be left in place and maintained for the life of the project or until the disturbed slopes have revegetated and stabilized.

- At sites without clay soils, where soils are moderate to highly permeable, as well as sites closer to ephemeral/perennial channels, the reserve pit (if used) would be lined with a 12- or 16-mil pit liner on top of a protective felt layer to minimize the potential for pit fluid leaks.

Vegetation

- During the construction phase of the project, Berry would implement an intensive reclamation and weed control program after each segment of project completion. Berry would reseed all portions of well pads and road and pipeline ROWs not utilized for the operational phase of the project. Reseeding would be accomplished using native plant species indigenous to the Project Area. Post-construction seeding applications would continue until determined successful by the Forest Service. Weed control would be conducted through an approved Pesticide Use and Weed Control Plan from the Authorized Officer. Weed monitoring and reclamation measures would be continued on an annual basis (or as frequently as the Authorized Officer determines) throughout the life of the project.

Wildlife

- Well pad and road construction, roads upgrading, and drilling operations would not be conducted between November 15 and April 30, to protect elk winter range.
- Existing guzzlers present near proposed well pads would be moved by Berry to reduce the impacts of increased traffic and human presence on elk, mule deer, and other wildlife utilizing those structures for drinking.

Air Quality and Noise

- As needed, Berry would apply water to utilized roads to reduce fugitive dust from vehicle traffic. If water application does not adequately reduce fugitive dust, the use of Magnesium Chloride (MgCl) would be considered.
- Berry would participate in multi-party, basin-wide air quality monitoring studies to monitor possible air quality impacts from the proposed activities, and help determine the effectiveness or need for air quality mitigation measures.
- Pump jack engines would be equipped with high grade mufflers to reduce noise during the operational life of the project.

Cultural Resources

- All ground disturbing activities (road construction and upgrading, well pad construction, etc.) would be conducted so as to avoid any impacts to identified cultural resource sites.
- If cultural resources were inadvertently discovered, construction activities would be halted and the Forest Service notified. Operations in the area of the discovery would not resume until authorization to proceed has been received from the Forest Service.

Plan Conformance Review

The Proposed Action is subject to and has been reviewed for conformance with the following plans (43 CFR 1610.5, BLM 1617.3):

Name of Plan: Ashley National Forest Land and Resource Management Plan (Forest Plan) and amendments.
Date Approved: Forest Plan 1986; amended for Oil and Gas Leasing and Development in 1997. The 1997 Western Uinta Basin Oil and Gas Leasing EIS described the environmental effects, including the cumulative effects, of oil and gas leasing and development in the Ashley National

Forest South Unit. The programmatic EIS for the Proposed Action will address potential environmental impacts from development and operation of up to 400 oil and gas wells within the Project Area, which is located within the larger Ashley National Forest South Unit.
Decision Number/Page: Pages 1-12, Record of Decision, effective September 1, 1997.
Decision Language: To allow mineral exploration and development on lands not withdrawn for other uses or restricted to mineral activity.

No Action Alternative

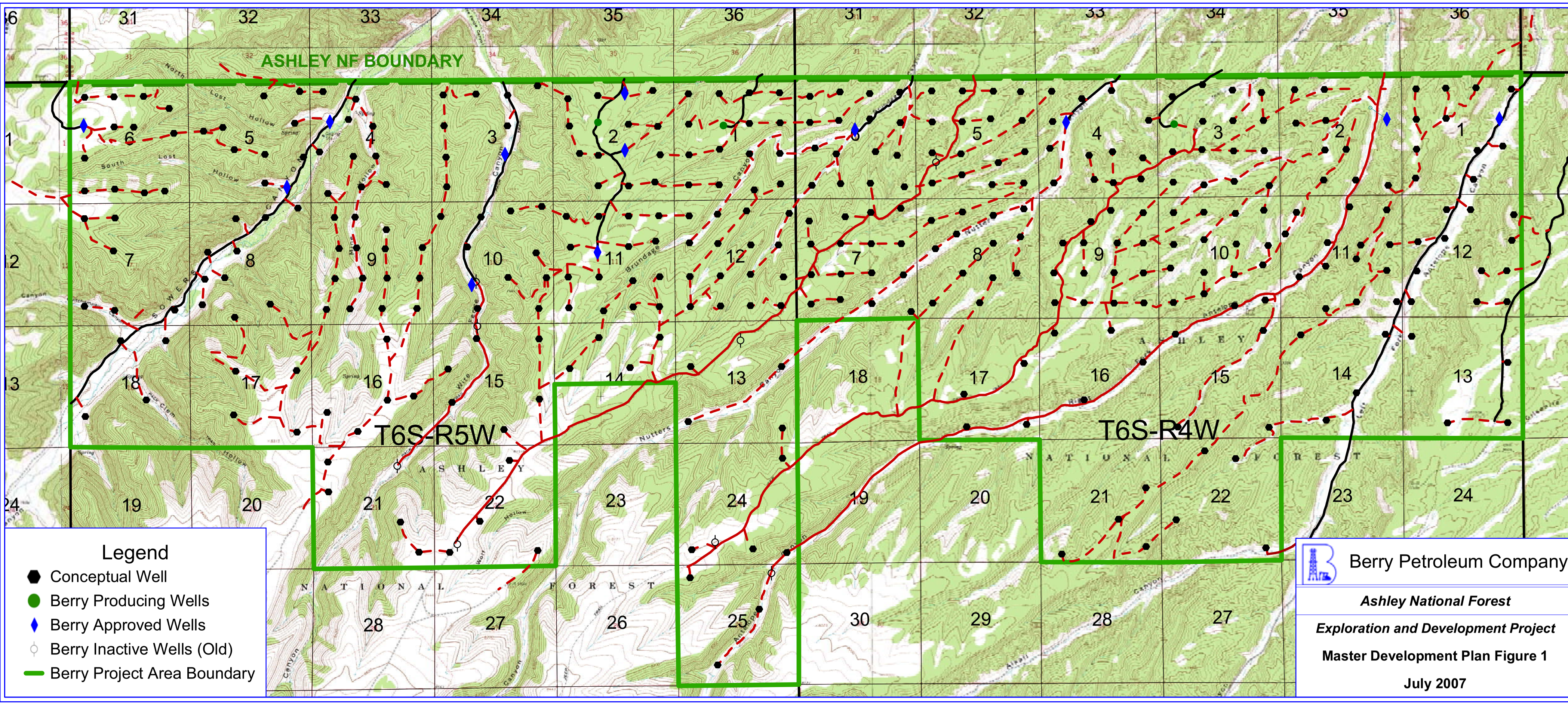
The Proposed Action affects federal subsurface minerals that are encumbered with federal oil and gas leases granting the lessee a right to explore and develop those oil and gas leases. The No Action alternative constitutes denial of the Proposed Action. Absent a non-discretionary statutory prohibition against drilling, the National Forest Service cannot deny the right to drill and develop the leasehold. Only Congress can completely prohibit development activities (Western Colorado Congress, 130 IBLA 244, 248 (1994), citing Union Oil Co. of California v. Morton, 512 F.2d 743, 750-51 (9th Cir. 1975). Overall, the No Action alternative has been considered but eliminated due to existing lease rights involved.

Table 1-1. Federal Mineral Leases and Associated Stipulations

Lease Number	Description of Lands	Stipulations
UTU-77314 UTU-77321 UTU-77322 UTU-77323 UTU-77324 UTU-77325 UTU-77326 UTU-77327 UTU-77328 UTU-77329 UTU-77330	SPECIFIC LOCATIONS	NSO: Lands with steep slopes exceeding 35%.
	SPECIFIC LOCATIONS	NSO: Lands with geologic hazards or unstable soils.
	ALL LANDS	CSU: Sensitive plants/wildlife species. Surveys to be conducted prior to surface disturbing activities to determine the possible presence of any sensitive species. Operations will be designed to or located so as not to adversely affect the viability of the species.
	SPECIFIC LOCATIONS	CSU: Specified semi-primitive non-motorized/roadless areas. Activities should be located, designed, and reclaimed in a manner that minimizes effects to the semi-primitive character of the land.
	ALL LANDS	Timing Limitation: Elk winter and yearlong range (11/15 - 4/30).
	ALL LANDS	Lease Notice: Cultural and Paleontological Resources. Leased lands should be examined to determine if cultural or paleontological resources are present prior to any surface disturbing activities. Site-specific field inventories may be required with acceptable inventory reports. Implementation of mitigation measures will be required by the Forest Service to preserve or avoid destruction of cultural or paleontological resources. The lessee or operator shall notify the Forest Service of any cultural or paleontological resources discovered as a result of surface operations and shall leave such discoveries intact until directed to proceed by the Forest Service.
	ALL LANDS	Lease Notice: Endangered or threatened species. Leased lands are to be examined prior to surface disturbing activities to determine potential effects upon plant or animal species listed or proposed for listing as endangered or threatened, or their habitats. Surface disturbing activities may be restricted or disallowed if those activities would violate the Endangered Species Act of 1973 by detrimentally affecting an endangered or threatened species or their habitats.
	ALL LANDS	Lease Notice: Floodplains and wetlands. All activities within these areas may be precluded or restricted in order to comply with Executive Orders 11988 and 11990, in order to preserve and restore or enhance the natural and beneficial values served by floodplains and wetlands. Mitigation measures deemed necessary to protect these areas will be identified in the environmental analysis. These areas are to be avoided to the extent possible or special measures such as road design, well pad size and location, or directional drilling, may be made part of the permit authorizing the activity.

U-5635 U-8894 U-8894A	ALL LANDS	Standard Lease Terms. Protection of surface, natural resources, and improvements. To prevent operations from unnecessarily: • Contributing to soil erosion • Damaging forage and timber growth • Polluting reservoirs, streams, springs, and wells • Damaging improvements of the surface owner or other permittees Upon conclusion of operations, the lessee must restore the surface to its former condition as can reasonably be done.
U-5637 U-8895 U-8895A	ALL LANDS	Standard Lease Terms. Protection of surface, natural resources, and improvements. To prevent operations from unnecessarily: • Contributing to soil erosion • Damaging forage and timber growth • Polluting reservoirs, streams, springs, and wells • Damaging improvements of the surface owner or other permittees Upon conclusion of operations, the lessee must restore the surface to its former condition as can reasonably be done.
	ALL LANDS	Additional stipulations: Before the destruction of any timber, permission from the authorized representative of the Secretary of Agriculture must be obtained, and such timber should be paid for at rates prescribed by such representative. No land disturbances, including drilling, excavation, or operations should take place within 200 ft. of any standing building unless authorized by such representative. All sump holes, ditches and other excavations should be fenced or filled, all debris should be removed or covered, and the surface of the lands should be restored, so far as reasonably possible, to their former condition.
	ALL LANDS	Additional stipulations: All efforts must be taken to prevent and suppress forest, brush, or grass fires on leased lands. During periods of serious fire danger, the lessee shall prohibit smoking and cooking fires on the lands. This prohibition should be enforced by all means within the lessee's power. Furthermore, no rubbish burning is allowed without proper authorization and the lessee must build fire lines or clear lands as the authorized representative decides is essential for fire prevention. Finally, the lessee must maintain appropriate fire tools at his headquarters or at appropriate locations on the lands.
	ALL LANDS	Additional stipulations: In conducting its operations, the lessee shall do all things reasonably necessary to prevent or reduce scarring and erosion of the land, pollution of the water resources and damage to the watershed. The lessee agrees to repair damage to the watershed or pollution of water resources and take corrective measures to prevent further damage or pollution as deemed necessary by the Forest Service.

	ALL LANDS	Additional stipulations: All efforts shall be taken to limit interference with existing land uses and commitments including: grazing, timber cutting, special use permits, water developments, ditch, road, trail, pipeline, telephone line, and fence rights-of-way. Also, cattle guards should be installed to prevent the passage of livestock across boundaries.
	ALL LANDS	Additional stipulations: Any part of the lands that lie within a municipal watershed or are deemed valuable for watershed protection, the lessee shall reseed or restore vegetative cover as required.
U-8897	ALL LANDS	Same stipulations as described above for leases U-5637 U-8895, and U-8895A and;
	ALL LANDS	Additional stipulations: No wells may be drilled at a location that would result in undue waste of oil shale. Wells may only be drilled if they do not inter with mining and recovery of oil shale deposits, or the extraction of shale oil by in situ methods. The drilling or abandonment of any well on this lease shall be done according to applicable operating regulations to prevent the infiltration of oil, gas or water into formations containing oil shale deposits or into mines or workings being utilized in the extraction of such deposits.



ASHLEY NF BOUNDARY
T6S-R5W
T6S-R4W
ASHLEY NATIONAL FOREST
Legend
Conceptual Well
Berry Producing Wells
Berry Approved Wells
Berry Inactive Wells (Old)
Berry Project Area Boundary
Berry Petroleum Company
Ashley National Forest
Exploration and Development Project
Master Development Plan Figure 1
July 2007
PETRA 7/13/2007 11:48:57 AM

APPENDIX 1

Master 13 Point Surface Use Plan

1. EXISTING ROADS

A. The 400 proposed well pad locations and associated access roads have been laid out conceptually and are shown on the attached topographic map (Figure 1). The proposed well pad locations were sited to utilize existing roads as much as possible. The siting of individual well locations and access road routes will be shown on detailed plats and described in site-specific APDs at the time of APD submittal.

B. Access Roads – refer to Figure 1 for a conceptual layout of roads, including existing roads to be upgraded in the Project Area. Specific improvements to existing access roads will be noted in site-specific APDs and will be designed and constructed in accordance with National Forest Service (FS) specifications.

C. Access Roads within a one-mile radius – refer to Figure 1.

D. All existing roads will be maintained and kept in good repair during all drilling, completion, and producing operations associated with the proposed oil and gas wells.

2. PLANNED ACCESS ROADS

A. Planned access roads are conceptually shown on Figure 1. Access roads and surface disturbing activities will conform to standards outlined in the BLM and Forest Service publication, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, Fourth Edition, 2006 (Gold Book) and/or Forest Service specifications. These specifications or ROWs will be attached to the site specific APDs when approved.

B. Surface disturbance and vehicular traffic will be limited to the approved location and approved access road and pipeline routes. Any additional area needed will be approved in advance.

C. New access roads will be crowned (2 to 3%), ditched, and constructed with a running surface of 22 feet and a maximum disturbed width of 35 feet. Graveling or capping the roadbed will be performed as necessary to provide a well constructed, safe road. Prior to construction or upgrading, the proposed road shall be cleared of any snow and shall be allowed to dry completely.

D. The disturbed width needed may be wider than 35 feet to accommodate larger equipment where deep cuts are required for road construction; intersections or sharp curves occur; or, as proposed by the operator. Approval will be required from the Forest Supervisor.

E. Appropriate water control structures will be installed to control erosion.

F. Unless stated in the site specific APDs, the following specifications will apply:

- The road grade in the Project Area will be 10% or less, wherever possible. The 10% grade would only be exceeded in areas where physical terrain or unusual circumstances require it.

- Turn-out areas will not be constructed unless they were deemed necessary for safety reasons.

- There will be no major cuts and fills, culverts, or bridges. If it becomes necessary to install a culvert at some time after approval of the APD, the operator will submit a Sundry Notice requesting approval of the FS Authorized Officer.

- The access road will be centerline flagged during time of staking.

- There will be no gates, cattle guards, fence cuts, or modifications to existing facilities without prior consent of the FS.

G. Surfacing material may be necessary, depending upon weather conditions.

H. The road surface and shoulders will be kept in a safe and usable condition and will be maintained in accordance with the original construction standards. Best efforts will be made such that all drainage ditches and culverts will be kept clear and free flowing and will be maintained according to the original construction standards.

I. The access road ROW will be kept free of trash during operations.

J. All traffic will be confined to the approved running surface.

K. Road drainage crossings shall be of the typical dry creek drainage crossing type. Crossings shall be designed so they will not cause siltation or accumulation of debris in the drainage crossing, nor shall the drainages be blocked by the roadbed.

L. Erosion of drainage ditches by runoff water shall be prevented by diverting water off at frequent intervals by means of cutouts.

M. Should mud holes develop, the holes shall be filled in and detours around the holes avoided.

N. When snow is removed from the road during the winter months, the snow should be pushed outside the borrow ditches, and the cutouts kept clear so that snowmelt will be channeled away from the road.

3. LOCATION OF EXISTING WELLS WITHIN A ONE MILE RADIUS

Please refer to Figure 1.

4. LOCATION OF TANK BATTERIES, PRODUCTION FACILITIES, AND PRODUCTION GATHERING AND SERVICE LINES

A. At each well location, surface disturbance will be kept to a minimum. Each well pad will be leveled using cut and fill construction techniques described in detail on the survey plats included with the APDs.

B. Should drilling result in established commercial production, the following will be installed for each well:

   1. A pump jack equipped with an internal combustion drive engine fueled by produced natural gas or propane, two 400-barrel crude oil tanks equipped with gas-fired heaters, and surface production pipelines to convey the crude oil from the pump jack to the tanks, surface gas gathering lines to transport produced natural gas off-site, a produced water decant tank set within secondary containment, and well site instrumentation to measure production and monitor operating conditions. The pump jack engines will be equipped with high grade mufflers to minimize noise impacts on adjacent areas.

   2. All gas gathering lines will be laid on the surface, except at road crossings where they will be buried to a depth of 2 feet. Surface pipelines will generally be placed adjacent to the access roads. Also, a specific description of the proposed gas gathering pipelines and a map illustrating the proposed route will be submitted with the site-specific APDs.

   3. Pipeline rights-of-way will be requested on the APDs.

   4. The area used to contain the proposed production facilities will be built using native materials. If these materials prove unacceptable, arrangements will be made to acquire appropriate materials from private sources.

   5. A containment dike will be constructed completely around those production facilities that contain fluids (i.e., production tanks, produced water tanks). This dike will be constructed of subsoil, be impervious, and hold 150% of the capacity of the largest tank. The site-specific APDs will address additional capacity if such is needed due to environmental concerns. The use of topsoil for the construction of dikes will not be allowed. If a Spill Prevention, Control, and Countermeasure (SPCC) Plan is required by the Environmental Protection Agency, the containment dike may be expanded with the Forest Service Authorized Officer’s approval to meet SPCC requirements.

   6. All permanent (on site for six months or longer) structures constructed or installed will be painted a flat, non-reflective, earth tone color to match one of the standard environmental colors, as determined by the five-state Rocky Mountain Inter-Agency Committee. All facilities will be painted within six months of installation. Facilities required to comply with the Occupational Safety and Health Act (OSHA) will be excluded. The required paint color will be designated by the Authorized Officer.

   7. Gas meter runs will be located approximately 100 feet from the wellhead. Where necessary, the gas line will be anchored down from the wellhead to the meter. Meter runs will be housed and/or fenced if needed.

   8. All site security guidelines identified in Federal regulation 43 CFR 3126.7 will be adhered to. All off-lease storage, off-lease measurement, or commingling on-lease or off-lease production will have prior written approval form the BLM/VFO Authorized Officer.

9. If different production facilities are required, a Sundry Notice will be submitted.

C. Berry Petroleum Company will protect all survey monuments, witness corners, reference monuments and bearing trees in the affected areas against disturbance during construction, operation, maintenance and termination of the facilities authorized herein. Berry Petroleum Company will immediately notify the authorized officer in the event that any corners, monuments or markers are disturbed or are anticipated to be disturbed. If any monuments, corner or accessories are destroyed, obliterated or damaged during construction, operation or maintenance, Berry will secure the services of a Registered Land Surveyor to restore the disturbed monuments, corner or accessories, at the same location, using surveying procedures found in the Manual of Surveying Instructions for the Survey of the public Lands of the United States, latest edition. Berry will ensure that the Registered Land Surveyor properly records the survey and shall send a copy to the authorized officer.

D. During drilling and subsequent operations, all equipment and vehicles will be confined to the access road ROW and any additional areas as specified in the approved Application for Permit to Drill.

E. Reclamation of disturbed areas no longer needed for operations will be accomplished by grading, leveling and seeding, as recommended by the Ashley National Forest.

5. LOCATION AND TYPE OF WATER SUPPLY

A. Water for the drilling and completion of the proposed oil and gas wells will be hauled by truck from a variety of existing permitted water sources. The water volume used in drilling operations is dependent upon the depth of the well and any losses that might occur during drilling. In general, water will be obtained from the closest available source to reduce hauling distance and cost. Water sources that will be used by Berry include:

- Berry source wells located in Sec. 23, T5S, R5W or Sec. 24, T5S, R5W (Permit # 43-11041);
- Duchesne City Culinary Water Dock located in Sec. 1, T4S, R5W;
- East Duchesne Water, Arcadia Feedlot, Sec. 28, T3S, R3W;
- Myton (Moon) Pit, SE/NE Sec. 27, T3S, R2W;
- Petroglyph Operating Company 08-04 Waterplant, Sec. 8, T5S, R3W;
- Kenneth V. & Barbara U. Richens source well located in Sec. 34, T3S, R2W (Permit # 43-1723);
- Brundage Canyon Field produced water;
- Produced water from previous wells in the Ashley NF; or
- Leo Foy source well located in Sec. 34, T5S, R5W (Permit # 43-11324).

A water use agreement is also in place with the Ute Indian Tribe.

6. SOURCE OF CONSTRUCTION MATERIALS

A. All construction materials for well locations and access roads will be borrowed materials accumulated during the construction of well locations and access roads.

B. Additional gravel or pit lining material will be obtained from a private source.

C. The use of materials under BLM jurisdiction will conform to 43 CFR 3610.2-3.

7. METHODS OF HANDLING WASTE MATERIALS

A. Drill cuttings will be contained and buried in the reserve pit or cuttings pit if a closed loop drilling system is used.

B. Drilling fluids, including salts and chemicals, will be contained in the reserve pit. Upon termination of drilling and completion operations, the liquid contents of the reserve pit will be used at the next drill site or will be removed and disposed of at an approved waste disposal facility. For wells completed from October 1 through April 30, any hydrocarbons in the pit shall be removed from May 1 to September 30 in accordance with 43 CFR 3162.7-1.

Unless specified in the site specific APD, the reserve pit will be constructed on the location and will not be situated within natural drainages where a flood hazard exists, or surface runoff will destroy or damage the pit walls. The reserve pit will be constructed so that it will not leak, tear, or allow discharge of liquids.

The reserve pit will be lined with a synthetic reinforced liner a minimum of 12 millimeters thick, with sufficient bedding used to cover any rocks. The liner will overlap the pit walls and be covered with dirt and/or rocks to hold it in place. Trash or scrap that could puncture the liner will not be disposed of in the pit.

Reserve pit leaks are considered an unacceptable and undesirable event and will be orally reported to the Authorized Officer.

C. Drain tanks will be installed with a 3” sand or dirt pad underneath a 16 millimeter thick liner which will extend 12” over the top edges of the pit. There will be room around the outside walls of the tank for visual inspection. There will be an escape route for animals from the bottom of the pit to ground level.

D. All fluids from swabbing new completions or recompletions will be returned into a production tank or a frac tank.

E. After first production, produced wastewater will be trucked to one of the following approved waste water disposal sites: R.N. Industries, Inc. Sec. 4, T2S, R2W, Bluebell; MC & MC Disposal Sec. 12, T6S, R19E, Vernal; LaPoint Recycle & Storage Sec. 12, T5S, R19E, LaPoint or Water Disposal Inc. Sec. 32, T1S, R1W, Roosevelt; used in the operations of the field or, unless prohibited by the Authorized Officer, stored in the approved reserve pit for a period not to exceed 90 days.

F. All production fluids will be disposed of at approved disposal sites. Produced water, oil, and other byproducts will not be applied to roads or well pads for control of dust or weeds. The indiscriminate dumping of produced fluids on roads, well sites, or other areas will not be allowed.

G. Any spills of oil, gas, salt water, or other noxious fluids will be immediately cleaned up and removed to an approved disposal site.
H. Self-contained, chemical portable toilets will be provided for human waste disposal. Upon completion of operations, or as needed, the toilet holding tanks will be pumped and the contents thereof disposed of in the nearest approved sewage disposal facility.

I. Garbage, trash, and other waste materials will be collected in portable, self-contained, fully enclosed trash cages during operations. Accumulated trash will be disposed of at an authorized sanitary landfill. Trash will not be burned on location.

J. All debris and other waste materials not contained in the trash cage will be cleaned up and removed from the location promptly after removal of the completion rig (weather permitting).

K. Any open pits will be fenced during the operations. The fencing will be maintained with best efforts until such time as the pits are backfilled.

L. No chemicals subject to reporting under SARA Title III (hazardous materials) in an amount equal to or greater than 10,000 pounds will be used, produced, stored, transported, or disposed of annually in association with the drilling, testing, or completion of wells. Furthermore, extremely hazardous substances, as defined in 40 CFR 355, in threshold planning quantities, will not be used, produced, stored, transported, or disposed of in association with the drilling, testing, or completion of wells within these areas.

8. ANCILLARY FACILITIES

A. Self-contained travel-type trailers may be used on-site during drilling operations. Standard drilling operation equipment to be on location will include: drilling rig with associated equipment; living facilities for the company representative, tool pusher, mud logger, directional driller (in some cases), toilet facilities and trash containers.

B. Facilities other than those described in this surface use plan to support drilling operations will be submitted to the Authorized Officer via a Sundry Notice (form 3160-5) for approval prior to commencing operations.
C. A closed system for drilling wells in the adjacent Brundage Canyon Field on Tribal lands is taking place at some locations. Where appropriate and permitted by the Forest Service, this approach may also be utilized on many of the proposed wells.

9. WELLSITE LAYOUT

A. A location layout diagram describing drill pad cross-sections, access road, cuts and fills, and locations of mud tanks, reserve pit, flare pit, pipe racks, trailer parking, spoil dirt stockpile(s), and the surface materials stockpile(s) will be included with the site-specific APDs.

B. The Location Layout Diagram will describe rig orientation, parking areas, and access roads as well as the location of the following:

- The reserve pit.

- The stockpiled topsoil. Topsoil shall not be used for facility berms. All brush removed from the well pad during construction will be stockpiled with the topsoil.

- The flare pit, which will be located downwind from the prevailing wind direction.

- The access road.

C. All reserve pits will be fenced according to the following minimum standards:

- 39-inch net wire shall be used with at least one strand of wire on top of the net wire. Barbed wire is not necessary if pipe or some type of reinforcement rod is attached to the top of the entire fence.

- The net wire shall be no more than two inches above the ground. The barbed wire shall be three inches over the net wire. Total height of the fence shall be at least 42 inches.

- Corner posts shall be cemented and/or braced in such a manner as to keep the fence tight at all times.

- Standard steel posts shall be used between the corner posts. Distance between any two posts shall be no greater than 16 feet.

- All wire shall be stretched using a stretching device before it is attached to the corner posts.

- The reserve pit fencing will be on three sides during drilling operations and on the fourth side when the rig moves off location. Pits will be fenced and maintained until cleanup.

10. PLANS FOR RECLAMATION OF THE SURFACE

The dirt contractor will be provided with approved copies of the Surface Use Plan and associated Standard Operating Procedures prior to construction and subsequent reclamation activities over the life of the project.

A. Construction Phase

1. Prior to the construction of proposed well locations and access roads, the top 12 inches of soil material (if present) will be stripped and stockpiled for future reclamation efforts. Placement of the topsoil will be noted on the location plat attached to the site-specific APDs. Topsoil shall be stockpiled separately from subsoil materials. Topsoil salvaged from the reserve pit shall be stockpiled separately near the reserve pit for subsequent reclamation of the reserve pit after the end of drilling and completion operations.

B. Production Phase

1. Upon well completion, within 30 days the location and surrounding area will be cleared of all unused tubing, materials, trash, and debris not required for production.

2. The portion of the well pads not required for production, the reserve pits, and access road cuts and shoulders will then be backfilled, leveled, and recontoured to mimic the adjacent terrain.

3. The reserve pits will be reclaimed within 180 days from the date of well completion, weather permitting. Once reclamation activities have begun, the activities will be completed within 30 days. Prior to backfilling the reserve pits, the fence surrounding the pits and all debris in the pits will be removed. Before any dirt work associated with reserve pit restoration takes place, the reserve pits shall be as dry as possible. The pit liners will be folded, torn, and perforated after the pits dry and prior to backfilling. After the reserve pits have been reclaimed, no depressions in the soil covering the reserve pit will be allowed. The object is to keep seasonal rainfall and runoff from seeping into the soil used to cover the reserve pit. Diversion ditches and water bars will be used to divert runoff as needed.

4. Upon completion of backfilling, leveling and recontouring, the stockpiled topsoil will be evenly spread over the portion of the well pads not required for production, the reserve pits, and access road cuts and shoulders. These temporarily disturbed areas will then be reseeded. Prior to reseeding, all disturbed areas will be scarified and left with a rough surface. The Ashley National Forest will be contacted for the required seed mixture. Seed will be broadcast and the amount of seed mixture per acre will be doubled. The seeded area will then be “walked” with a dozer to assure coverage of the seeds.

C. Final Reclamation of Dry Holes and Well Locations at the End of Project Life

For dry holes, final reclamation of well locations and roads will take place within a reasonable timeframe, weather permitting, after the well is drilled, plugged, and abandoned. Similarly, at the end of the productive lives of successful wells, the well locations, access roads, and other disturbed areas will be restored to near their original condition. Reclamation procedures that will be followed on the Ashley National Forest include:

1. At final abandonment, all well casings shall be cut off at the base of the cellar or 3 feet below final restored ground level, whichever is deeper, and capped with a metal plate a minimum of 0.25 inches thick. The cap will be welded in place and the well location and identity will be permanently inscribed on the cap. The cap also will be constructed with a weep hole.

2. Well locations, associated roads that will no longer be used, and other disturbed areas will be restored as near as practical to their original condition. All disturbed areas will be re-contoured to approximate the natural topography.

3. Upon completion of recontouring, stockpiled topsoil will be evenly spread over the well locations, access roads, and other disturbed areas. These areas will then be reseeded. Prior to reseeding, all disturbed areas will be scarified and left with a rough surface. The Ashley National Forest will be contacted for the required seed mixture. Seed will be broadcast and the amount of seed mixture per acre will be doubled. The seeded area will then be "walked" with a dozer to assure coverage of the seeds.

4. Any drainages rerouted during the construction activities shall be restored to their original line of flow, or as near as possible.

11. SURFACE OWNERSHIP

United States Forest Service. Fee ownership in portions of Sections 7, 18, and 18 of Township 6 South, Range 5 West. Surface ownership will be noted on all site-specific APDs.

12. OTHER INFORMATION

A. All lease and/or unit operations will be conducted in such a manner that full compliance is made with all applicable laws, regulations, Onshore Oil and Gas Orders, the approved Plan of Operations, and any applicable Notice to Lessees. The operator is fully responsible for the actions of his subcontractors. A copy of these conditions will be furnished to the field representative to ensure compliance.

B. The operator will control noxious weeds along access road use authorizations, pipeline route authorizations, well sites or other applicable facilities. A list of noxious weeds may be obtained from the NFS, BLM, or the appropriate County Extension Office. On NFS administered land, it is required that a Pesticide Use Proposal be submitted and approved prior to the application of herbicides or other pesticides or possibly hazardous chemicals.

C. Drilling rigs and/or equipment used during drilling operations on this location will not be stacked or stored on NFS-administered lands after the conclusion of drilling operations, or at any other time, without authorization by the NFS. If authorization is obtained, such storage is only a temporary measure.

D. Travel is restricted only to approved travel routes.

E. Unless previously conducted, a Class III archaeological survey will be conducted on all NFS lands that may experience surface disturbance. All personnel will refrain from collecting artifacts and from disturbing any significant cultural resources in the area. The operator is responsible for informing all persons in the area who are associated with this project that they may be subject to prosecution for knowingly disturbing historic or archaeological sites or for collecting artifacts. All vehicular traffic, personnel movement, construction, and restoration activities shall be confined to the areas examined, as referenced in the archaeological report, and to the existing roadways and/or evaluated access routes. If historic or archaeological materials are uncovered during construction, the Operator is to immediately stop work that might further disturb such materials and contact the Authorized Officer.

Within five working days, the Authorized Officer will inform the operator as to:

- Whether the materials appear eligible for the National Historic Register of Historic Places;
- The mitigation measures the operator will likely have to undertake before the site can be used (assuming in-situ preservation is not necessary); and,
- The time frame for the Authorized Officer to complete an expedited review under 36 CFR 800.11 to confirm, through the State Historic Preservation Officer, that the findings of the Authorized Officer are correct and that the mitigation measures are appropriate.

If the operator wishes, at any time, to relocate activities to avoid the expense of mitigation and/or the delays associated with this process, the Authorized Officer and/or the surface owner will assume responsibility for whatever recordation and stabilization of the exposed materials may be required. Otherwise, the operator will be responsible for mitigation costs. The Authorized Officer and/or the surface owner will provide technical and procedural guidelines for the conduct of mitigation. Upon verification from the Authorized Officer that required mitigation has been completed, the Operator will then be allowed to resume construction.

F. On surface administered by the FS, all surface use will be conducted in accordance with the STIPULATION FOR LANDS OF THE NATIONAL FOREST SYSTEM UNDER JURISDICTION OF THE DEPARTMENT OF AGRICULTURE, including:

- If the surface is owned by another entity (FEE OWNER) and the mineral rights are owned by the BLM, a ROW will be obtained from the other entity.
- Operator’s employees, including subcontractors, will not gather firewood along roads constructed by the operator.
- All well site locations will have appropriate signs indicating the name of the operator, the lease serial number, the well name and number, and the survey description of the well (either footages or the quarter/quarter section; the section, township, and range).
- All new roads constructed by the operator will have appropriate signs. Signs will be neat and of sound construction. The sign will state that the land is located within the Ashley National Forest boundary, the name of the Operator, firearms are prohibited, and only authorized personnel are permitted.

13. OPERATOR'S REPRESENTATIVE AND CERTIFICATION

A) Representative:

NAME:	Thomas W. Rand Utah Asset Manager
ADDRESS:	Berry Petroleum Company 950 17th Street, Suite 2400 Denver, CO 80202
PHONE: CELLULAR:	303-825-3344 720-384-5149
EMAIL:	TWR@bry.com

All lease and/or unit operations will be conducted in such a manner that full compliance is made with all applicable laws, regulations, Onshore Oil and Gas Orders and any applicable Notice to Lessees.

The operator will be fully responsible for the actions of its subcontractors. A complete copy of the approved "Applications for Permit to Drill" and the Standard Operating Procedures will be furnished to the field representative(s) to ensure compliance and shall be on location during all construction and drilling operations.

The drilling permit will be valid for a period of one year from the date of approval. After permit termination, a new application will be filed for approval for any future operations.

B) Certification:

I hereby certify that I, or persons under my direct supervision, have inspected the proposed drill site and access route; that I am familiar with the conditions which presently exist; that the statements made in this plan are, to the best of my knowledge and belief, true and correct; and that the work associated with the operations proposed herein will be performed by Berry Petroleum Company and its contractors and subcontractors in conformity with this plan and the terms and conditions under which it is approved. This statement is subject to the provisions of 18 U.S.C. 1001 for the filing of a false statement.

Thomas W. Rand
Thomas W. Rand
Utah Asset Manager
Berry Petroleum Company

1-18-07
Date

United States
Department of
Agriculture

Forest
Service

January 2012

Appendix B
Reclamation Plan

South Unit Oil and Gas Development Final Environmental Impact Statement

Duchesne Ranger District, Ashley National Forest
Duchesne County, Utah

Table of Contents

1.0 INTRODUCTION

The following erosion control, revegetation, mitigation, and management measures are designed to attain successful reclamation of disturbed areas associated with the full field oil and gas exploration and production project on the South Unit of the Ashley National Forest (ANF). These measures are established to reclaim disturbances associated with this project and were developed based on:

1) U.S. Department of Agriculture (USDA) Forest Service Ashley National Forest Land and Resource Management Plan (Forest Service 1986);
2) Western Uinta Basin Leasing Final Environmental Impact Statement (FEIS) and Record of Decision (ROD) (Forest Service 1997);
3) U.S. Department of the Interior (USDI) BLM/Forest Service Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development (Gold Book) (USDI-USDA 2007);
4) Berry Petroleum's 2006 Oil and Natural Gas Exploration Project Environmental Assessment (Forest Service 2006);
5) Berry Petroleum's Master Development Plan (Appendix A);
6) Impacts identified in the Environmental Consequences chapter (Chapter 3) of this EIS;
7) Coordination with Forest Service staff; and
8) Issues identified during the scoping process.

Disturbed areas to be reclaimed include drill pad sites, staging areas, access roads, and pipeline rights-of-way (ROWs). Due to the large geographic area covered by the project and the lack of site-specific locations of project facilities at this time, the following measures are presented in a general, non-specific manner. Final selection and modifications of these measures would be identified by the Forest Service in coordination with Berry Petroleum Company (the Operator).

This reclamation plan outlines measures that would be implemented to effectively reclaim areas disturbed during the construction phase of the proposed project. These measures would be followed unless exceptions are granted or actions are modified by agreement between the Forest Service and the Operator. These measures describe how natural gas development activities should be managed to assure compliance with the resource management goals and objectives for the general area, applicable lease and unit area stipulations, and resource limitations identified during interdisciplinary team (IDT) analyses. Initial monitoring for compliance and successful implementation of the mitigation measures would be under the direction of the Operator. Final approval and release would be under the direction of the Forest Service.

Reclamation measures covered in this plan fall into two general categories: interim and final.

Interim Reclamation: Interim reclamation refers to measures applied to stabilize disturbed areas and to control runoff and erosion during periods when application of final reclamation measures is not feasible or practicable. Typical interim reclamation measures include recontouring of disturbed surfaces not associated with production and the stabilization of soil by revegetating sites where recontouring is needed and/or where periodic disturbance may continue to occur due to operation and maintenance activities.

Final Reclamation: Final reclamation refers to measures that are to be applied concurrently with completion of drilling and pipeline installation. Final reclamation of an area that is not planned for further disturbance includes recontouring, stabilization of the soil by revegetation, and restoration of the ecosystem function originally found at the site.

2.0 OBJECTIVES

This plan is designed to meet the following objectives for reclamation of disturbed areas.

- Minimize disturbance of the existing environment and avoidance of sensitive areas such as riparian corridors, wetlands, and steep slopes.
- Control and minimize surface runoff, erosion, and sedimentation through the use of Best Management Practices (BMPs) for storm water management (i.e., diversion and water treatment structures).
- Isolate and/or remove all undesirable materials (i.e., contaminated soils, potentially hazardous materials, trash).
- Soil stabilization through establishment of a vegetative ground cover on disturbed sites.
- Restoration of the previously disturbed or removed native plant community, or restoration of an alternative vegetative regime in consultation with and approval of the Forest Service.
- Implementation of policies to resist the introduction and spread of noxious weeds.
- Annual monitoring and management of reclamation sites to evaluate, control, and report on invasive and noxious weeds beginning the first season of disturbance and continued on an annual basis until final reclamation is met.

3.0 PERFORMANCE STANDARDS

The most effective principle for successful restoration of disturbed sites is to limit the initial disturbances through the use of planning, construction control, and adaptive management. Restoration planning should start before on-site disturbance begins and should remain an integral part of the operational plan throughout the construction process. Understanding the existing site conditions, and adapting construction techniques towards responding to these conditions, is the first step towards implementing an effective reclamation plan.

The following general reclamation performance standards are to be used as a guideline to determine whether a reclamation effort is successful and whether the reclamation liability (i.e., bonds) would be released.

- There shall be no contaminated materials remaining at or near the surface. All buried undesirable materials shall be physically isolated, using proven methods, for long-term stabilization, consistent with state and other federal regulations.
- The subsurface shall be properly stabilized, holes and underground workings (wells, etc.) properly plugged, and subsurface integrity and long-term stability ensured.
- The final reclaimed area shall be stable and exhibit none of the following characteristics:
  - unnaturally large rills or gullies;
  - perceptible soil movement, mass wasting, or head cutting on disturbed slopes;
  - slope instability adjacent to the reclaimed area; or
  - drainages showing signs of active down cutting or deposition.
- The overall landscape contour shall be appropriate and useable for the planned post-reclamation land use.
- The soil surface must be stable and have adequate surface roughness to reduce runoff and capture rainfall and snow melt. Additional short-term measures (such as applying mulch or mechanical surface roughening) shall be used to limit surface soil movement.
- Vegetation production and relative species diversity shall approximate the surrounding undisturbed area. The vegetation shall stabilize the site and support the planned post-disturbance land use, provide for natural plant community succession and development, be self-perpetuating, and be free of noxious weeds. This shall be demonstrated by the following:
  - Successful on-site establishment of desirable native species.
  - Evidence of desirable vegetation reproduction, either spreading by rhizomatous species or seed production.
  - Generally, native species shall be used in all revegetation efforts. However, BLM Manual 1745 (BLM 1992) describes those situations where non-natives may be substituted.
  - Integration with the adjacent undisturbed vegetation and compatibility with the post-disturbance land use.
- The reclaimed landscape shall blend with the visual composition and characteristics of the adjacent area and not result in a change of the Scenic Quality Rating of the existing landscape. Overall location, landform, scale, shape, color, or orientation of major landscape features must be considered and meet the needs of the planned post-disturbance land use.
- The Operator shall conduct routine monitoring during and following reclamation activities. This is further outlined in subsequent sections of this plan.

3.1 Performance Standards for Each Location

For each well pad and associated infrastructure, a site-specific reclamation plan would be prepared, submitted, and approved by the Forest Service before operations begin. This plan should include an assessment of pre-disturbance vegetative communities, including the diversity of species and the percent existing vegetative cover in the planned construction area, as well as BMPs for storm water quality to prevent erosion and sediment runoff from the site. Seed mixtures would be certified weed-free and appropriate to the site based on existing native vegetative communities. Reclamation monitoring reports would be prepared by the Operator or a third-party contractor and submitted to the Forest Service on an annual basis.

With the exception of active work areas, all disturbed highly erosive or sensitive areas to be left bare or unprotected for more than one month would have at least 50% cover of protective material in the form of mulch, matting, or vegetative growth. All disturbed areas should have at least a 50% cover of protective material within six months after disturbance.

3.2 Standards Prior to First Full Growing Season

Reclamation actions for completed sites would be implemented before the first full growing season following disturbance with the goal of returning the land to a condition approximate to or more productive than that which existed before disturbance or to stable and productive conditions compatible with the site-specific, pre-construction reclamation plan for the disturbed area. Prior to the first full growing season after completion of work on a site, the Operator would:

- stabilize disturbed site soils for revegetation with no hindrance to germination and growth of seed; and
- properly prepare the site by:
  - recontouring;
  - completing soil preparation activities, such as ripping, straw crimping, and seedbed preparation;
  - seeding with approved seedling/seed mixtures using site-specific methods for successful revegetation; and
  - ensuring that weed treatments are compatible with seed mixtures and plantings.

3.3 Start of First Growing Season

- Monitor germination and plant growth in reclaimed area.
- Work with the Forest Service to detect and control weeds in all areas.
- Use adaptive management to correct establishment and growth problems.

3.4 End of First Growing Season

- Complete a site-specific vegetation monitoring report for areas being reclaimed.
- Establish photo points of disturbed areas so that repeatable measurements can be conducted annually through the five-year monitoring period.
- Prepare a written, site-specific prescription for additional actions to be implemented, including:

- reseeding of areas not attaining reclamation success;
- stabilization of soil;
- control and removal of noxious, non-native and/or invasive weeds; and
- mulching, fertilization, or other practices recommended to enhance vegetative growth in the following season.

3.5 End of Second Growing Season

- The density and abundance of desirable species is at least three to four seedlings per linear foot of drill row (if drilled) or transect (if broadcast).
- Total vegetative cover would be at least 50% of pre-disturbance vegetative cover as measured along the reference transect for establishing baseline conditions.

3.6 End of Monitoring Period – Determination of Success

- Total vegetative cover would be at least 70% of pre-disturbance vegetative cover as measured along the reference transect for establishing baseline conditions.
- Ninety percent of the revegetation, as measured along the reference transect for establishing baseline conditions, consists of species included in the seed mixture and/or that occur in the surrounding natural vegetation, or is deemed desirable and acceptable by the Forest Service.
- Erosion condition of the reclaimed areas is equal to or better than that measured for the reference transect for establishing baseline conditions.

4.0 RECLAMATION PLAN

The reclamation process would consist of the following steps: pre-disturbance planning; site preparation; interim reclamation; final reclamation; and reclamation success monitoring.

4.1 Pre-disturbance Planning

Pre-disturbance planning minimizes the amount of reclamation at a site by reducing land disturbance. Planning for reclamation prior to construction is critical to successful reclamation efforts in the future. Reclamation becomes significantly more difficult, more expensive, and less effective if sufficient topsoil is not salvaged, interim reclamation measures are not completed, and proper care is not taken to construct pads and roads in locations that minimize reclamation needs.

During selection of drill site, road, pipeline, and ancillary facility locations, the Operator would avoid the following areas, where practical:

- Areas with high erosion potential (i.e., rugged topography, steep slopes, floodplains).
- Areas located in, or near, riparian areas, intermittent or ephemeral stream channels, or riparian zones.

Prior to disturbance, the Operator would conduct on-site inspections with the Forest Service, an assigned designee of the Forest Service, or other representative for each proposed disturbance area to determine the suitability of proposed facility locations and/or corridors with regard to the above-listed avoidance areas. The Operator would submit relevant site-specific reclamation plans to the Forest Service for approval prior to initiation of environmental disturbance on site.

Storm Water Pollution Prevention Plans (SWPPPs) would be prepared for all project activities requiring greater than 1 acre of disturbance to ensure that storm water runoff would not cause surface water pollution. The SWPPP would include provisions for periodic inspection of storm water pollution prevention devices and practices. A Notice of Intent would be submitted to the Utah Department of Environmental Quality. Copies of the SWPPP and subsequent inspection reports would be filed at the Operator's local office.

Heavy equipment contractors would be provided with approved copies of the Surface Use Plan (SUP) and associated Standard Operating Procedures (i.e., site-specific reclamation plans, SWPPPs, Spill Prevention, Control and Countermeasure Plans [SPCCPs], etc.) prior to construction and subsequent reclamation activities over the life of the project (LOP). To assure surface reclamation would occur at the end of the productive LOP, the Operator or its successor operator(s) would secure a reclamation bond with the Forest Service. The Operator would also ensure compliance with relevant components of the BMPs detailed in Chapter 3 of this EIS including, but not limited to, drilling multiple wells on an individual well pad; centralization of production facilities; closed loop drilling; and minimizing topsoil removal during drilling activities.

Bonding is required for oil and gas lease operations to ensure that the Operator performs all obligations of the lease contract, including plugging leasehold wells, surface reclamation, and cleanup of abandoned operations (USDI-USDA 2007).

4.2 Site Preparation

4.2.1 Trash and Spills

Trash removal would occur routinely throughout field development and operation. Trash would be picked up by field personnel and disposed of at on-site trash receptacles. These receptacles would be serviced by a licensed solid waste contractor.

Spills would be handled in accordance with Operator-specific SPCCPs for the field. Disposal of trash and spilled materials would be handled in accordance with all applicable regulations.

4.2.2 Topsoil and Spoil Handling

Prior to the construction of proposed well pads, the top 12 inches of soil material in the construction area would be stripped and stockpiled for future reclamation efforts. Topsoil would be salvaged and stockpiled from all proposed disturbance areas unless the Forest Service deems that leaving topsoil in place would facilitate better reclamation. Vegetation would be salvaged and stockpiled along with the topsoil to incorporate native seeds and organic matter. Spoil would be salvaged and stockpiled separately from topsoil. Topsoil and spoil stockpile locations would be clearly noted on site maps and in the site-specific reclamation plan.

For pipelines and access roads constructed on slopes of less than 15%, topsoil would be salvaged from all areas to be disturbed and stockpiled in windrows within the construction ROW by sidecasting with a grader. Where pipelines and access roads are constructed on slopes steeper than 15%, topsoil would be transported to more level terrain for storage. All stockpiles would be located so as not to affect existing drainages.

Topsoil and spoil stockpiles would be designed to minimize surface area and remain stable until they are used for reclamation. Stockpile slopes would be 5:1 or less. If a topsoil stockpile is located on or adjacent to ground that slopes 3:1 or more, runoff would be diverted around the stockpile via interceptor ditches. Interceptor ditches would be V-shaped—1 foot deep and 3 feet wide with gently sloping sides—and would empty into native, undisturbed, non-wetland vegetation. In addition, energy dispersing devices (i.e., rock aprons) would be placed at each end of the interceptor ditch. If topsoil piles exceed 3 feet in height or would be stored for 2 years or longer, the Operator would develop a plan for Forest Service approval that details methods and procedures to maintain or replace nutrients and soil microbial viability for reclamation.

Where access roads and/or pipelines must cross wetlands or drainages, construction would occur when the area is dry, if possible. In work areas that would not be excavated, but would be driven on (i.e., scalped pipeline corridors adjacent to pipeline trenches), vegetation would be cut to ground level, leaving existing root systems intact. These areas would not be graded. If standing water or saturated soils are present, either wide-track/balloon-tire construction equipment or typical construction equipment operated on equipment pads would be used. Equipment pads would be removed immediately upon completion of construction.

4.3 Interim Reclamation

Processes involved for successful interim reclamation include surface and seedbed preparation, revegetation, and erosion management.

Interim reclamation would be deemed successful when the following standards are met:

- No contaminated materials occur at or near the surface, and all buried undesirable materials are removed from the site or encapsulated in impermeable material and covered with at least 4 feet of spoil (with the consent of the Forest Service).

- The subsurface is stable. Holes are plugged and no indications of subsidence, slumping, or significant downward movement of surface soil materials is visible.
- Surface areas are stable and do not exhibit evidence of:
  - active sheet flow;
  - actively eroding rills or gullies greater than 2 inches wide or deep;
  - perceptible soil movement or head cutting in drainages; and
  - slope instability on or adjacent to the reclaimed area.
- Soil surfaces have adequate surface roughness to reduce runoff and to capture rainfall and snow melt.
- Reclamation areas exhibit vegetative reproduction, either by spreading of rhizomatous species or seed production, and free of noxious and non-native/invasive species. Non-native species may be present only with Forest Service approval.
- Applicable performance standards for relevant time periods described in Section 3.0 have been achieved.

Interim reclamation would begin in the first fall (September 15 to freeze-up) or spring (prior to May 15 and only if fall seeding is not feasible) following completion of required activities.

Upon well completion, the well locations and surrounding areas would be cleared of all unused tubing, materials, trash, and debris not required for production within a reasonable time. Prior to backfilling disturbed areas, the sites would be as dry as possible, fencing surrounding the sites would be removed, all debris would be properly discarded and pit liners would be folded, torn, and perforated. The portion of the well pads not required for production, the reserve pits, areas around buried or surface pipeline, roadside ditches, and portions of the road ROWs not used as running surfaces would then be backfilled, leveled, and recontoured to mimic the adjacent terrain. Upon completion of backfilling, leveling, and recontouring, the stockpiled topsoil would be evenly spread over the site. Prior to reseeding, all disturbed areas would be scarified and left with a rough surface. Areas would then be reseeded using an appropriate seed mixture. Designated seed mixtures in the appropriate amounts would be distributed across the disturbed areas. The seeded area would then be “walked” with a dozer to ensure coverage of the seeds. Once begun, interim reclamation activities would be completed within 30 days.

4.3.1 Surface and Seedbed Preparation

4.3.1.1 Backfilling and Grading

Backfilling would occur prior to grading. Areas to be backfilled include flare pits, reserve pits, cut slopes, pipeline trenches, borrow ditches, and facility foundations. Pipeline trenches would be backfilled so that the surface is at or near the pre-existing grade. Spoil for backfill would be obtained from fill material and spoil stockpiles.

Reclaimed areas would be graded to blend with adjacent topography and approximate the site's original contours. Area-wide drainage would be restored so surface runoff flows and gradients are returned to conditions present prior to disturbance. Graded surfaces would be suitable for the replacement of a uniform depth of topsoil, would promote cohesion between subsoil and topsoil layers, would reduce wind erosion, and would facilitate moisture capture.

Specialized grading techniques would be applied at the Operator's discretion and with the consent of the Forest Service and may include slope rounding, bench grading, stair-stepping, and/or contour furrowing. Dozers, loaders, scrapers, and motor graders are machinery typically used for backfilling and grading.

4.3.1.2 Ripping and Disking

Compacted areas such as roads and well pads would be ripped or disked to a depth of approximately 6 to 8 inches to improve soil aeration, water infiltration, and root penetration. Ripped areas would be disked, if necessary, to fill in deep furrows and break up large clods. Motor graders or tractors equipped with ripping shanks are typically used for ripping.

4.3.1.3 Topsoil Replacement

Proper topsoil replacement and seedbed preparation maximizes seeding efficiency and improves reclamation success.

Waterbars and erosion control devices would be installed on reclaimed areas prior to topsoil replacement, as necessary, to control topsoil erosion.

All stockpiled topsoil would be redistributed uniformly on reclamation areas. If the stockpile for a given location contains insufficient topsoil to meet the required 6-inch minimum, topsoil would be mixed with suitable spoil or imported from another location. Topsoil is typically replaced using scrapers, dozers, and/or motorgraders.

Once topsoil is replaced, seeding would occur within 2 weeks unless the ground is wet or frozen. In this circumstance, seeding would be delayed until the ground dries or thaws to the point where soils are suitable for seeding.

The Operator has the discretion to conduct soil fertility tests and/or use fertilizers; however, fertilizers are not required for the initial efforts at final reclamation because fertilizers generally are not effective in semi-arid climates. In addition to fertilizer use, the Operator has the discretion to use other amendments such as inoculation with soil microorganisms, lime, organic matter, etc. Fertilizers would not be used near open water. If final reclamation success standards are not met within a reasonable time period, soil tests could be implemented to determine other measures to ensure successful final reclamation.

After topsoil replacement, newly topsoiled areas would be disked or harrowed to reduce soil compaction, to break up soil clods, to improve root and water penetration, and to provide a friable but firm seedbed. The surface may be roughened to reduce wind and water erosion and to promote moisture capture. If the surface is roughened during disking, other moisture-capture techniques probably are not necessary. However, the Operator has the full discretion to implement techniques such as pitting and gouging to concentrate water in pits and gouges. If final reclamation success standards are not met within a reasonable time period, the Forest Service may require implementation of these techniques.

4.3.1.4 Revegetation

4.3.1.4.1 Seeding

Reclaimed areas would be seeded using seed mixtures approved by the Forest Service. These mixtures would be based on the following criteria: general conditions within the area, species adaptations to site conditions, usefulness of the species for rapid site stabilization, species success in past revegetation efforts, seed costs and availability, and compliance with *Executive Order 13112: Invasive Species*. Executive Order 13112 requires federal agencies to identify, prevent, and mitigate invasive plant species infestation.

Alternative species and seeding rates may be used at the Operator's discretion, if warranted by site-specific conditions or seed availability, provided that the alternative species/seeding rates facilitate achieving reclamation success and all modifications are documented in the site-specific Reclamation Plan. The Operator would determine which seed mixture to use and which substitute species may be appropriate to include in the mixture in consultation with the Forest Service. The Operator may also elect to use interseeding techniques. The Forest Service may require interseeding or inoculation techniques if reclamation is not successful. The Operator would have the discretion to inoculate selected seed mixtures with soil microorganisms to facilitate germination and growth. Seed mixtures must be certified weed-free.

Seeding would be conducted in the fall between September 15 and freeze-up. If fall seeding is not feasible, seeding may occur between spring thaw and May 15. Seeds would be planted along contours using a rangeland drill equipped with an agitator and depth bands to mix seed and ensure proper seeding depths. Seeds would be planted 0.25 to 0.50 inch deep. Fluffy seeds (i.e., winterfat) would be broadcast simultaneously with drilled seeding. Broadcast seeding may be used, at the Operator’s discretion, for other shrub and forb species, using either hand or specialized broadcast seeders. The Operator may elect to broadcast seed after applying and crimping 2 tons/acre of certified weed-free mulch.

Where drill-seeding is not practical due to steep slopes, rocky surfaces, or wet soil conditions, seeding rates would be doubled, seeds would be broadcast, and the area would be raked or chained to cover seeds.

The Operator may elect to hand plant bare-root or containerized shrub stock to facilitate shrub establishment. It is not required for initial attempts at revegetation, but may be required by the Forest Service at a later date if reclamation success is not achieved.

4.3.1.4.2 Mulching

Where mulching is deemed necessary, the reclaimed area would be uniformly mulched (75% minimum cover) with a certified weed-free native grass, hay, small grain straw, wood fiber, and/or live mulch, at a rate of 2 tons/acre. Alternatively, cotton, jute, or synthetic netting may be applied. Mulch would be crimped into the soil, tackified, or incorporated into the erosion control blankets to prevent it from blowing or washing away and from entering waterways. Mulch would protect the soil from wind and water erosion, raindrop impact, and surface runoff and would help hold seed in place. Mulching may occur prior to or after broadcast seeding, but must occur after drill seeding.

On steep slopes where it is unsafe to operate equipment, at sites where soils have 35% or more surface rock content, or on notably unstable areas, hydromulch, biodegradable erosion control netting, or matting would be firmly attached to the soil surface.

4.3.1.5 Erosion Control

4.3.1.5.1 Construction and Operation Phase Erosion Control

Erosion control practices have been designed into construction procedures described in Chapter 2 of this EIS. Site-specific SWPPPs would also describe specific sediment and erosion control measures. The Operator would also adhere to the following erosion control measures during construction and operation.

Culverts, road ditches, and road design would be used in accordance with industry standard engineering practices to minimize erosion along active roads. Culverts would be sized to pass expected flows without causing erosion above, below, or around the culvert. Culvert entrances and exits would be protected with energy dissipaters such as riprap or rock aprons, as necessary. Road ditches would be sized to collect runoff from roads and surrounding areas; energy dissipating structures such as straw bales anchored with rebar would be used to prevent ditch erosion. Water discharged from culverts, roadside ditches, and turnouts would be directed either into undisturbed vegetation or natural drainages.

Interceptor ditches would be installed above all cut slopes of 3:1 or greater. Interceptor ditches would be V-shaped—1 foot deep and 3 feet wide with gently sloping sides—and would empty onto native, undisturbed vegetation. Alternatively, energy-dispersing devices (i.e., rock aprons) would be placed at the end of the interceptor ditch. Sediment control devices would be placed at the base of all fill slopes and stockpiles.

Where road or pipeline construction occurs on slopes of 3:1 or more, temporary sediment barriers such as silt fences and/or staked weed-free straw bales would be installed along contour below the road/pipeline corridor. Silt fences or other sediment filtering devices would also be installed wherever road and pipeline construction occurs within 100 feet of a drainage or wetland. Temporary sediment barriers would remain in place until the surfaces are stable and final reclamation is obtained. Sediment filtering devices would be cleaned and maintained in functional condition throughout the LOP.

Trench plugs would be used during pipeline construction at non-flumed drainage crossings to prevent diversion of flows into upland portions of pipeline trenches. In-stream protection devices (i.e., drop structures) also may be used to prevent erosion in drainages crossed by pipelines. In drainages, clean gravel would be used for the upper 1 foot of backfill in pipeline trenches. Application of riprap to channel banks would be limited to areas where flow conditions prevent stabilization by vegetation. Riprap installation would comply with the U.S. Army Corps of Engineers Section 404 permitting requirements.

Pipeline trenches would be dewatered when necessary, so no construction-related sediment-laden water flows into drainage channels.

Where roads and pipelines cross a waterbody (i.e., wetlands or drainages), topsoil and spoil would be placed at least 10 feet from the edge of the waterbody, and sediment control structures would be placed between the topsoil/spoil and the waterbody. Dirt, rock, and brush riprap would not be used to stabilize the ROWs at waterbody crossings.

4.3.1.5.2 Reclamation Phase Erosion Control

All reclaimed surfaces would be left rough and would be mulched if recommended by the Forest Service. Erosion and sediment control structures would be installed on reclaimed areas wherever slope gradients exceed 3:1 and where monitoring demonstrates that erosion control structures are needed.

Runoff from reclaimed areas where slopes exceed 3:1 would be controlled using standard structures including, but not limited to, water bars, silt fences, geotextile fabric, and energy dissipaters. Water bars would be installed in accordance with standard BLM specifications and would drain into undisturbed vegetation. Water bars generally would be 12 to 18 inches in height with a 2% grade. Water bars would be installed after ripping and prior to topsoil placement. Silt fences would be placed downhill from reclaimed areas where erosion may impact a waterbody and would be installed according to manufacturer's instructions. Energy dissipaters would be used wherever water is channelized to slow flows.

All runoff and erosion control structures would be inspected and maintained by the Operator throughout the LOP. Inspections would occur after runoff events. Sites and sources of soil movement would be addressed in a timely manner. Inspection reports would be made available to the Forest Service upon request.

4.3.1.6 Weed Control

The Operator would be responsible for noxious, non-native, and invasive weed control from all project activities for the LOP. If use of herbicides is deemed necessary by the Operator or the Forest Service, a Pesticide Use Permit would need to be submitted to the Forest Service for approval. All herbicides would be used only in the season or growth stage during which they are most effective. Herbicides would be applied only by certified personnel using approved precautions and application procedures in compliance with all applicable federal, state, and local regulations. Herbicides would not be used within 100 feet of open water or during extremely windy conditions. Aerial application of herbicides would be prohibited within 0.25 mile of known special status plant species locations (i.e., federally listed or BLM-sensitive species) and hand application of herbicides would not occur within 500 feet of such occurrences. Certified weed-free seed mixtures and mulches would be used, thereby minimizing the potential for noxious weed introduction.

4.4 Final Reclamation

Final reclamation would be conducted on all disturbed areas no longer required for field operations (i.e., completed portions of well pads, road outslopes, pipeline corridors), as well as pads and roads for non-producing wells and on pads for wells that have reached the end of their productive life (including facility removal and complete well pad/access road reclamation). Final reclamation of disturbed areas is not necessarily a separate process from interim reclamation. All interim reclamation would be considered final unless monitoring shows that additional measures are necessary. The Operator would completely reclaim all portions of well pads not required for operations, access road out-slopes, and pipeline corridors in the fall or spring immediately following construction or dry hole abandonment. Reserve pits, if approved, would be completely reclaimed in the first spring or fall after draining. If reclamation involves facility removal, regrading and reseeding would occur in the first fall or spring following facility removal.

4.4.1 Facility Removal

When the Operator determines that a well or other facility is no longer needed, the facility would be removed and the area would be permanently reclaimed.

Unless specifically authorized, all gas and water wells would be abandoned according to BLM and Utah Division of Oil, Gas and Mining regulations. Aboveground well pads, pipelines, and water disposal facilities, including buildings, tanks, flare pits, reserve pits, evaporation pits, and associated hardware, would be dismantled, removed, and salvaged, re-used, or disposed of at approved sites. Underground pipelines would be purged of gas or liquid, plugged, and abandoned in place.

Liquid or solid wastes remaining at well locations would be tested and properly disposed of according to state and federal regulations. Reserve and evaporation pit liners would be disposed of at state-approved sites. Concrete foundations, pads, or footings would be broken up and removed.

Road reclamation would include the removal of bridges, culverts, cattleguards, sediment control structures, and signs. Drainage-crossing sideslopes would be reduced to no more than 4:1 grades to reduce bank erosion and produce stable sideslopes. Barriers would be used to discourage travel on the reclaimed roads and pipelines until final reclamation is deemed successful.

Upon completion of facility removal activities, the Operator would initiate the interim reclamation measures described in Section 4.3. Final reclamation would be deemed successful when all of the performance standards discussed in Section 3.0 have been achieved.

4.5 Reclamation Success Monitoring

The purpose of this monitoring guidance section is two-fold: 1) to document the condition of reclaimed areas relative to the revegetation success criteria; and 2) to provide an expeditious means for monitoring all reclamation sites to document reclamation progress.

4.5.1 Monitoring Responsibilities

The Operator would be responsible for the following:

- monitoring;
- determining if reclamation success standards have been met;
- developing and implementing remedial actions if success standards are not being met;
- reporting monitoring results to the Forest Service annually; and
- requesting concurrence from the Forest Service that success standards have been met and monitoring is no longer required.

The Forest Service would be responsible for the following:

- reviewing annual monitoring reports;
- providing or denying concurrence with the reclamation assessments as to whether success standards have been met;
- providing rationale for concurrence determinations; and
- providing input on remedial actions to facilitate reclamation success (i.e., implementing soil testing, soil amendments, irrigation, etc.).

The Operator would submit annual reclamation evaluation reports to the Forest Service by December 31 of each year and the Forest Service would complete its concurrence responsibilities by March 31 of the following year. This would enable the Operator to make necessary adjustments prior to the next field season (summer) and reclamation season (autumn).

4.5.2 Monitoring Approach

Monitoring of disturbed areas would include qualitative and quantitative approaches to assess reclamation success. These approaches would include monitoring growth of vegetative cover using photographic evidence, vegetative sampling, and documentation of interim and final reclamation on an annual basis.

4.5.2.1 Qualitative Approach

Monitoring would be largely qualitative because it is reasonably accurate to document the condition of a site in the field with appropriate notes and representative photographs. The approach designed herein is to allow reclamation inspectors a tool for evaluating reclamation status throughout the development during a short period in the growing season, which would enable the Operator to obtain field-wide and site-specific information on reclamation status. This record would be used to make a variety of informed decisions on actions necessary to obtain field-wide and site-specific reclamation success, including simple remedial actions such as fence installations. The record would be key to tracking reclamation progress and initiating appropriate remedial activities for the LOP.

4.5.2.2 Quantitative Approach

The qualitative evaluation may be supported by quantitative sampling such as the use of quadrats or transects to estimate vegetative cover. Quantitative or statistical sampling would only be conducted if it is deemed appropriate by the Operator or the Forest Service, or to settle disagreements in the interpretation of the qualitative evaluation. Quantitative vegetation assessments should be performed by an environmental professional with the skills to initiate and interpret an assessment and monitoring program.

4.5.3 Monitoring Interim Reclamation

Interim reclamation would be monitored annually and after large rain storms or snow melt runoff events. In order to limit variability in monitoring reports based on seasonal variations in vegetative cover, inspectors should attempt to complete annual monitoring at approximately the same time each season.

Interim reclamation monitoring would include visual inspection for undesirable materials, soil stability assessments, the effectiveness of erosion control practices, the status of vegetation establishment (including a species list and a determination of relative abundance), and observations of undesirable plant species. Monitoring results would be documented and color photographs accurately depicting the reclamation status would be taken.

4.5.4 Monitoring Final Reclamation

Final reclamation would be considered complete when all standards for interim reclamation have been achieved. Guidelines described in Section 4.5.3 would be followed. The Operator would request determination of success and release from monitoring once success criteria are met. No additional monitoring would be necessary.

5.0 REFERENCES

United States Department of Agriculture (USDA) Forest Service (Forest Service). 1986. Forest Plan for Land and Resource Management Plan. Ashley National Forest.

______. 1997. Western Uinta Basin Oil and Gas Leasing Final EIS and Record of Decision.

______. 2006. Berry Petroleum's 2006 Oil and Natural Gas Exploration Project Environmental Assessment.

United States Department of the Interior, Bureau of Land Management (BLM). 1992. Introduction, Transplant, Augmentation, and Reestablishment of Fish, Wildlife, and Plants, BLM Manual 1745. United States Department of the Interior, Bureau of Land Management. March 1992.

United States Department of the Interior (USDI) and United States Department of Agriculture (USDA). 2007. Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development. BLM/WO/ST-06/021+3071/REV 07. Bureau of Land Management. Denver, Colorado. 84 pp.

United States
Department of
Agriculture

Forest
Service

January 2012

Appendix C
Air Quality Technical Support Document

South Unit Oil and Gas Development Final Environmental Impact Statement

Duchesne Ranger District, Ashley National Forest
Duchesne County, Utah

Table of Contents

List of Tables and Figures

List of Appendices

1.0 INTRODUCTION

This Air Quality Technical Support Document (AQTSD) was prepared to summarize and provide a detailed description of analyses performed to quantify potential air quality impacts from the proposed Ashley National Forest South Unit Master Development Plan (the Project). The methodologies utilized in the analysis were originally defined in an air quality impact assessment protocol (Protocol) (ENVIRON, 2008) with input from the lead agency, U.S. Forest Service (USFS) and other air quality stakeholders. The AQTSD discusses those methodologies as necessary and summarizes the findings of the air emissions inventories and subsequent dispersion modeling analyses.

The Project's location in northeastern Utah required the examination of Project and cumulative source impacts in southwest Wyoming, western Colorado, and most of Utah (Figure 1). The analysis area includes the area surrounding the proposed Project Area and all or a portion of the Maroon Bells-Snowmass, West Elk, High Uinta, Holy Cross, Raggeds, Hunter Frying Pan, and Flat Tops Wilderness Areas; the Dinosaur and Colorado National Monuments; the Bryce Canyon, Capitol Reef, Canyonlands, Arches, and Black Canyon of the Gunnison National Parks as well as the Flaming Gorge National Recreation Area and the Brown Park National Wildlife Refuge.

Impacts analyzed include those on air quality and air quality related values (AQRVs) resulting from air emissions from: 1) Project sources within the Project Area, 2) non-Project state-permitted and reasonably foreseeable future action (RFFA) sources within the modeling domain, and 3) non-Project reasonably foreseeable development (RFD) sources within the modeling domain. The Project source emissions inventory was performed in accordance with the Protocol. Non-Project sources were originally inventoried as part of the Rawlins and Pinedale Resource Management Plan (RMP) revisions, the Atlantic Rim Natural Gas Development Project EIS air quality analysis, Moxa Arch Infill Development Project, the Hiawatha Regional Energy Development Plan Environmental Impact Statement, and the Pinedale Supplemental Environmental Impact Statement. Additional data from Wyoming, Colorado, and Utah air agencies were obtained for the non-Project sources.

The remainder of this Section describes the Project in further detail, provides a description of the alternatives proposed and evaluated, and presents a list of tasks performed for the study. Section 2.0 presents an overview of the emissions inventories. Descriptions of the near-field air quality impact assessment methodology and impacts are provided in Section 3.0, and Section 4.0 describes the CALPUFF analyses performed for assessment of far-field Project direct and cumulative impacts.

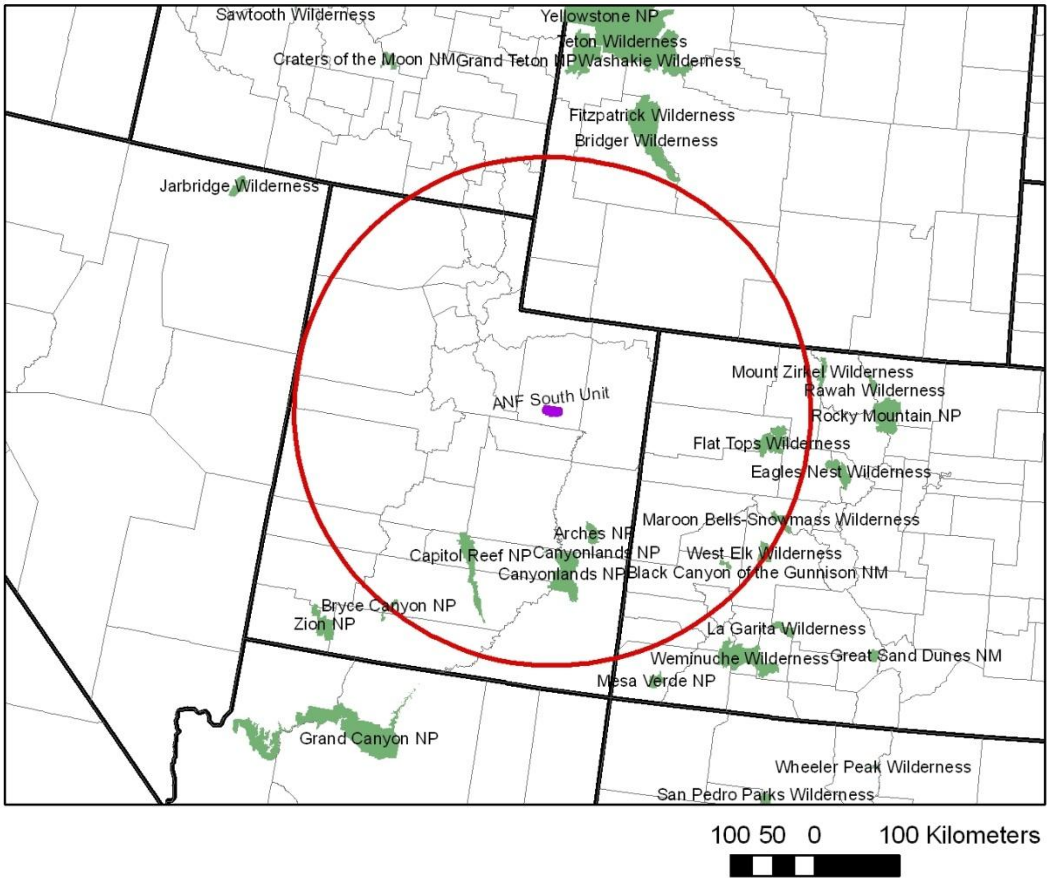


Figure 1. Ashley National Forest South Unit Project Area.
Project Location and Class I Areas within 300 km of the Project are shown.

1.1 PROJECT DESCRIPTION

Berry Petroleum Company (Berry or the Company) is proposing to drill up to 400 oil and gas wells on federal mineral leases the Company holds within the South Unit of the Ashley National Forest in Duchesne County, Utah. The purpose of the project is to explore for economically recoverable deposits of crude oil and/or natural gas and to produce those resources for delivery to market. The proposed Project Area is defined as Berry's current lease holdings within the South Unit of the Ashley National Forest, which cover an area of roughly 40.5 square miles (25,900 acres). This Project Area begins approximately 11 miles south of the town of Duchesne, Utah. The Project Area location and all Class I areas within a 300 km radius are shown in Figure 1.

All of the proposed wells would be drilled on existing federal mineral leases held by Berry. In general, in the northern portion of the Project Area, where economic quantities of oil and gas are more likely to be present, wells would be drilled on approximately 40-acre spacing. In the southern portion of the Project Area, the potential for occurrence of economic quantities of oil and gas is generally believed to be lower and a more exploratory spacing of approximately 160-acres is envisioned. The actual spacing and geographic distribution of wells over the life of the project would be based on actual discoveries of economic quantities of oil and gas resources. Berry expects to drill all of the proposed wells from 2009 through 2028 or 2029. It is possible that the Company could drill fewer than 400 wells because of geologic and market uncertainties. This plan is conceptual in nature and provides a maximum development scenario, assuming oil and gas is found in economic quantities throughout the Project Area.

Berry estimates that approximately 2.5 acres of surface terrain would be disturbed to create each well pad. The amount of surface disturbance at each well pad would vary on a site-by-site basis depending on topography. The proposed oil and gas wells would be drilled to an average depth of about 6,000 feet. The typical oil and gas well would require about 7 days to drill, 14 days to complete, with an additional 7 days or so for production equipment installation and well start up (about 28 days from spud to production). A typical well location could consist of one or two wellheads, a pump jack(s), and two 400-barrel capacity above ground crude oil tanks per well. The pump jacks would be driven by natural gas or propane-fired internal combustion engines equipped with high-quality noise-reducing mufflers. Crude oil would be hauled away by truck. On average, Berry estimates 1 truck trip would be required every 8 days per well to haul crude oil offsite to market. Gathered natural gas would be dehydrated and compressed at up to 4 new compressor stations within or adjacent to the Project Area.

Approximately 100 miles of new access roads and 21 miles of upgraded existing roads would be constructed to reach the proposed well pad sites. These roads would utilize a construction right-of-way (ROW) 35 feet wide during construction. After construction is complete and gas gathering lines are installed, approximately 13 feet would be rehabilitated leaving a 22-foot road surface. The Project would include approximately 130 miles of gas gathering pipelines. Low pressure lines would be poly pipe installed on the surface. High pressure lines would be made of steel and buried. Gas gathering pipelines would parallel access roads in the vast majority of cases and add virtually no additional surface disturbance as they would utilize the 35-foot road ROW. In some locations, surface pipelines would drop off of ridgelines to the valleys below. In total, approximately 130 miles of gas gathering pipelines would be required for this project.

1.2 STUDY TASKS

Modeling analyses were performed to quantify near-field pollutant concentrations within and nearby the Project Area from project-related emissions sources and were carried out such that maximum near-field impacts were estimated. Impacts from both construction and production activities were calculated. Emissions calculations for the Project and for other sources in the region are described in Section 2.0. Near-field impacts are described in detail in Section 3.0.

Direct project and far-field modeling analyses were performed to evaluate separately the expected impacts to air quality and air quality related values. Far-field impacts are described in greater detail in Section4.0.

The following tasks were performed for air quality and AQRVs impact assessment:

- Project Air Emissions Inventory. Development of an air pollutant emissions inventory for the Project.
- Regional Air Emissions Inventory. Development of an air pollutant emissions inventory for other regional sources not represented by background air quality measurements, including state-permitted sources, RFFA, and RFD.
- Project Near-Field Analysis. Assessment of near-field air quality concentration impacts resulting from activities proposed within and near the Project Area.
- Far-Field Direct Project Impact Analysis.
  - Quantitative assessment of far-field air quality concentration and AQRV impacts resulting from proposed Project activities.
  - Qualitative assessment of far-field ozone and greenhouse gas concentration impacts resulting from proposed Project activities.
- Far-Field Cumulative Impact Analysis.
  - Quantitative assessment of far-field air quality concentration and AQRV impacts resulting from activities proposed within the Project Area combined with other regional sources inventoried under second item above.

2.0 EMISSIONS INVENTORY

2.1 PROJECT EMISSIONS

The Project includes the development of up to 400 oil and natural gas wells. Wells will be developed on single well pads. Criteria pollutant and hazardous air pollutant (HAP) emissions were inventoried for construction activities, production activities, and ancillary facilities. Criteria pollutants included nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). HAPs consisted of n-hexane, benzene, toluene, ethylbenzene, and xylene (BTEX), and formaldehyde. Greenhouse gases were inventoried, but impacts due to these gases were not assessed in the near-field or far-field modeling. The inventory was developed using manufacturer's emissions data, the Environmental Protection Agency's (EPA's) AP-42 (EPA 1995) and NONROAD model (EPA 2004), Gas Research Institute (GRI) emission factors, UDEQ DAQ, CDPHE, and WDEQ Guidance, and other accepted engineering methods.

2.1.1 Construction Emissions

Construction activities are a source of criteria pollutants. Emissions would occur from well pad and resource road construction and traffic, drilling and associated traffic, completion/testing and associated traffic, pipeline installation and associated traffic, and wind erosion during construction activities. If all 400 natural gas wells are determined to be feasible, as many as 20 new wells could be drilled each year, assuming an even pace of development.

Well pad and resource road emissions would include fugitive PM_{10} and $PM_{2.5}$ emissions from 1) construction activities and 2) traffic to and from the construction site. Other criteria pollutant emissions would occur from diesel combustion in haul trucks and heavy construction equipment. On resource roads, water would be used for fugitive dust control, affecting a control efficiency of 50%.

After the pad is prepared, drilling would begin. Emissions would include fugitives from unpaved road travel to and from the drilling site and emissions from diesel drilling engines. Emissions from well completion and testing would include fugitive PM_{10} and $PM_{2.5}$ emissions from traffic and emissions from diesel haul truck tailpipes. Also, wind erosion emissions from disturbed areas would occur. The Operators do not expect to perform flaring.

Pollutant emissions would also occur from pipeline installation activities, including general construction activities, travel to and from the pipeline construction site, and diesel combustion from on-site construction equipment. Fugitive dust (PM_{10} and $PM_{2.5}$) emissions would occur during well pad, road, and pipeline construction due to wind erosion on disturbed areas.

A summary of single-well construction emissions is shown in Table 1. Construction emission calculations are provided in detail, showing all emission factors, input parameters, and assumptions, in Appendix A (Project Emissions Inventory).

2.1.2 Production Emissions

Field production equipment and operations would be a source of criteria pollutants and HAPs including BTEX, n-hexane, and formaldehyde. Pollutant emission sources during field production would include:

- combustion engine emissions and dust from road travel to and from well sites;
- diesel combustion emissions from haul trucks;
- combustion emissions from well site heaters;
- fugitive HAP/VOC emissions from well site equipment leaks;
- condensate storage tank flashing;
- glycol dehydrator still vent flashing;
- wind erosion from well pad disturbed areas;
- tank working/breathing losses and loadout;
- emissions from central compressors; and
- artificial lift engines.

Table 1**.** Single-Well Construction Emissions Summary (Tons/Year-well).

Category	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	CO2	CH4
Pad Construction	0.2079	0.0001	0.0775	0.0185	0.0113	0.0109	0.0040	0.0069	0.0003	0.0000	0.0040	0.0069	12.81	0.00
Well/Pipe Const FugDust	0.0000	0.0000	0.0000	0.0000	0.0271	0.0149	0.0000	0.0000	0.0122	0.0149	0.0000	0.0000		
Pad Construction Traffic	0.0007	0.0001	0.0033	0.0006	0.0433	0.0045	0.0001	0.0001	0.0388	0.0043	0.0001	0.0001		
Wind Erosion	0.0000	0.0000	0.0000	0.0000	0.0449	0.0000	0.0000	0.0000	0.0449	0.0000	0.0000	0.0000		
Pipeline Construction	0.0018	0.0000	0.0011	0.0003	0.0002	0.0002	0.0001	0.0001	0.0000	0.0000	0.0001	0.0001	0.15	
Drilling	1.2968	0.0155	0.1387	0.0189	0.0241	0.0233	0.0086	0.0147	0.0007	0.0000	0.0086	0.0147	107.45	0.07
Drilling Road Traffic	0.0147	0.0011	0.0543	0.0115	0.7948	0.0829	0.0014	0.0024	0.7119	0.0791	0.0014	0.0024		
Completion	0.0846	0.0001	0.0178	0.0037	0.0038	0.0037	0.0014	0.0023	0.0001	0.0000	0.0014	0.0023	10.42	0.00
Completion Road Traffic	0.0118	0.0008	0.0400	0.0092	0.6113	0.0639	0.0012	0.0021	0.5474	0.0606	0.0012	0.0021		
Install Prod Eq. Traffic	0.0022	0.0002	0.0084	0.0018	0.1222	0.0127	0.0002	0.0004	0.1095	0.0122	0.0002	0.0004		
Total Construction	1.6205	0.0178	0.3411	0.0644	1.6829	0.2171	0.0170	0.0291	1.4658	0.1710	0.0170	0.0291	130.8	0.1

Fugitive PM_{10} and $PM_{2.5}$ emissions would occur from road travel and wind erosion from well pad disturbances. A control efficiency of 50% was assumed for watering. Criteria pollutant emissions would occur from diesel combustion in haul trucks traveling in the field during production.

Heaters required at each well site include an indirect heater, a dehydrator reboiler heater, and a separator heater. Heater emissions for all pollutants were calculated using AP-42 emission factors and methods.

HAPs and VOC emissions would occur from fugitive equipment leaks (i.e., valves, flanges, connections, pump seals, and opened lines). Condensate storage tank flashing emissions also would include VOC/HAP emissions. Emissions from dehydration sources were provided by the Operators. Total production emissions of criteria pollutants and HAPs occurring from a single well are presented in Table 2. Production emission calculations are provided in detail in Appendix A, showing all emission factors, input parameters, and assumptions.

Table 2. Single-Well Production Emissions Summary (Tons/Year-well).

Category	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	Ethyl-Benzene	Xylene	n-Hexane	CO2	CH4
Tank W/B Losses	0.0000	0.0000	0.0000	0.7308	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0033	0.0521	0.0046	0.0308	0.0130	0.0001	0.0004
Heaters	0.1072	0.0000	0.0901	0.0059	0.0081	0.0081	0.0020	0.0061	0.0000	0.0000	0.0020	0.0061	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	128.6670	0.0025
Artificial Lift Engines	1.1047	0.0001	0.8285	0.3264	0.0177	0.0177	0.0087	0.0090	0.0000	0.0000	0.0087	0.0090	0.0187	0.0014	0.0005	0.0000	0.0002	0.0000	100.2144	0.2095
Flashing	0.0000	0.0000	0.0000	5.8203	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0265	0.4150	0.0367	0.2451	0.1039	0.0006	0.0029
Fugitives	0.0000	0.0000	0.0000	0.7248	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0016	0.0004	0.0008	0.0022	0.0090	1.8070
Production Traffic	0.0128	0.0020	0.0986	0.0101	1.0716	0.1093	0.0009	0.0015	0.9624	0.1069	0.0009	0.0015								
Tank Loadout	0.0000	0.0000	0.0000	0.1274	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0091	0.0008	0.0054	0.0023	0.0000	0.0001
Total Production	1.22	0.00	1.02	7.75	1.10	0.14	0.01	0.02	0.96	0.11	0.01	0.02	0.02	0.03	0.48	0.04	0.28	0.12	228.89	2.02

2.1.3 Determination of Modeled Year

In order to provide a conservative estimate of peak emissions from the Project, we determined the year during the life of the Project during which maximum emissions may be expected. This is the scenario for which the CALPUFF impact assessment was performed. The life of the Project is 20 years, and we assume that the wells are constructed at an even pace of 20 wells per year. Therefore, construction emissions for each year of the project are based on the construction of 20 wells. Production emissions for the Project will increase each year, with the final year (year 20) of the Project having the largest production emissions. In order to ensure that emissions are at a maximum during the modeled year, it is assumed that all four compressor stations are completed and operational during this year.

2.1.4 Total Field Emissions

Annual emissions in the Project Area are shown in Table 3. Emissions assume construction and production occurring simultaneously in the field and include one year of maximum construction emissions plus one year of production at maximum emission rates.

Construction emissions were based on well construction, drilling, drilling traffic, completion traffic, and completion flaring. Well construction emissions were based on the number of wells constructed per year. Drilling, drilling traffic, and completion traffic were based on the number of wells developed per year. No completion venting or flaring operations were assumed to occur at any of the wells under construction. Production emissions were calculated based on the total number of producing wells in the field. Total producing wells were equal to the difference in number of wells proposed and the number of wells constructed per year.

Table 3**.** Estimated Ashley Project Maximum Annual In-field Emissions Summary - Construction and Production.

Annual Development Rate per year	Total Producing Wells	Pollutant	Total Emissions (tpy)
20	380	PM_{10}	453
		$PM_{2.5}$	58.3
		NO_x	611
		SO_2	1.18
		CO	512
		VOCs	3212
		HCHO	22.3
		Benzene	17.1
		Toluene	185
		Ethyl-Benzene	16.3
		Xylene	108
		n-Hexane	53.4
		CO_2	118,504
		CH_4	1,134

2.1.4.1 Greenhouse Gas Emissions

Project greenhouse gas emissions were quantified in terms of CO_2 equivalents. At the request of the U.S. Forest Service, direct CH_4 and CO_2 emissions from well pad construction and production sources and central compressor stations were quantified following the methods in the Hells Gulch/Hightower EA (Buys and Associates, 2008). In addition, guidance from API (2004) was used. Estimates of fugitive emissions from equipment leaks were made. Emissions of N_2O were assumed to be small in comparison with CH_4 and CO_2 emissions (API, 2004). Details of the calculations are provided in Appendix A. The total annual project-only CO_2 equivalent emissions for the Ashley Project's peak emissions year are compared to state and U.S. national annual CO_2 equivalent emissions in Table 4. Table 4 shows that the Ashley Project comprises a small percentage of the total Utah, Colorado, Wyoming, and U.S. greenhouse gas budgets.

Table 4**.** Greenhouse Gas Emission Comparison.

	CO_2 Equivalents (metric tons/year)	Ashley %
Ashley Project[1]	1.06E+05	100%
United States (2006)	7.08E+09	0.001%
Utah (2005)	6.88E+07	0.154%
Colorado (2005)	1.18E+08	0.090%
Wyoming (2005)	5.60E+.07	0.189%

[1] Year of Maximum emissions

2.2 REGIONAL EMISSION INVENTORY

An emissions inventory of industrial sources within the Project Area cumulative modeling domain was prepared for use in the cumulative air quality analysis. The modeling domain included portions of Wyoming, Colorado, and Utah (see Figure 1). Industrial sources and oil and gas wells permitted within a defined time frame (January 1, 2001 through December 31, 2007) through state air quality regulatory agencies and state oil and gas permitting agencies were first researched. The subset of these sources which had begun operation as of the inventory end-date was classified as state permitted sources, and those not yet in operation were classified as RFFA. Also included in the regional inventory were industrial sources proposed under NEPA in the states of Wyoming, Utah, and Colorado. The developed portions of these projects were assumed to be either included in monitored ambient background or included in the state-permitted source inventory. The undeveloped portions of projects proposed under NEPA were classified as RFD. RFD was defined as 1) the NEPA-authorized but not yet developed portions of Wyoming and Colorado NEPA projects, and 2) not yet authorized NEPA projects for which air quality analyses were in progress and for which emissions had been quantified (Table 5).

Future tar sand and oil shale development is expected in the study area (BLM, 2008a), but had not been quantified in sufficient detail to allow for a quantitative evaluation of future year emissions at the time of writing of this AQTSD.

The regional inventory, including methodologies used to compile the regional source emissions, is provided in Appendix B and includes a description of the data collected, the period of record for the data collected, inclusion and exclusion criteria, stack parameter data, and the state-specific methodologies required due to differences in the format and completeness of data obtained from each state.

Table 5. Potential RFD in the Ashley Study Area.

Hiawatha HREDP	Atlantic Rim	Hickey Table Mountain	Moxa Arch
Roan Plateau	Continental Divide	Uinta Basin	Desolation Flats
Vernal Field Office	Creston-Blue Gap	South Baggs	Dripping Rock
Black Butte Coal Pit	Copper Ridge	Figure 4 Gap EA	EGL Resources Oil Shale EA
Spaulding Peak	Gant Gulch GAP EA	Orchard Unit GAP EA	Grass Mesa GAP EA
Castle Springs GAP EA	Wheeler to Webster GAP EA	Rulison GAP EA	Pete and Bill Creek GAP EA
Alkali Creek Compressor Station			

3.0 NEAR-FIELD MODELING ANALYSES

3.1 MODELING METHODOLOGY

A near-field ambient air quality impact analysis was performed to quantify the maximum criteria pollutant (PM_{10}, $PM_{2.5}$, CO, NO_2, SO_2) and HAPs (BTEX, n-hexane, and formaldehyde) impacts that could occur within and near the Ashley Project area. These impacts would result from emissions associated with Project construction and production activities, and are compared to applicable ambient air quality standards and significance thresholds. Emissions of each pollutant analyzed were examined to determine 1) the maximum emissions phase during well/field development and 2) the maximum emissions phase during production, and these scenarios were modeled to determine maximum near-field project impacts.

The current EPA guideline air quality models for near-source air quality and far-field air quality and AQRV impact assessments are the AERMOD Gaussian Plume and CALPUFF puff models, respectively (EPA, 2003c; 2005). The Utah Department of Environmental Quality (UDEQ) Division of Air Quality (DAQ) was contacted about appropriate AERMOD meteorological databases for the Ashley Forest application and recommended against using AERMOD due to insufficient meteorological data in the region near the Project. Instead, the UDEQ DAQ recommended that EPA's Industrial Source Complex (ISC) Short Term Model Gaussian plume model be used.

EPA's Industrial Source Complex Short Term Model ISCST3 (Brode and Wang, 1992), as released on February 4, 2002, was used to assess the near-field impacts of the Project. ISCST3 is a steady-state Gaussian plume model which can be used to assess pollutant concentrations from a wide variety of sources associated with an industrial complex. This model can account for settling and dry deposition of particles; downwash; point, area, line, and volume sources; plume rise as a function of downwind distance; separation of point sources; and limited terrain adjustment. Two separate versions of the ISC model are available to permit both long-term (ISCLT) and short-term (ISCST) air quality impact analysis. The primary difference between the two models is the type of weather data needed as input. The short-term version, ISCST, was designed to calculate contaminant concentrations over time periods as short as one hour. The ISCST model can be used to calculate ambient concentrations over longer time periods (for example one year), simply by averaging the hourly predictions over the appropriate averaging period. Because the ISCST predictions are based upon more detailed meteorological inputs, the predictions from the ISCST model are more accurate than those estimated using the ISCLT model. Thus, the ISCST short-term model was used in this analysis.

3.2 METEOROLOGY DATA

Four years of hourly meteorology data were used for the near-field analysis. All four years of surface observations were collected in Bonanza, UT, from January-December for the years of 1985, 1986, 1987, and 1992. The upper-air meteorological data consisted of twice-daily atmospheric soundings from the Grand Junction Colorado National Weather Service Office. Grand Junction is the closest site to the Ashley Project area that has consistent atmospheric soundings. All meteorological files were provided by the Utah Division of Air Quality (DAQ). The files were preformatted for use with the ISCST3 model and were quality assured before modeling commenced.

Wind roses for each of the four years of data are presented in Figures 2 through 5 below. Prevailing winds are northeasterly.

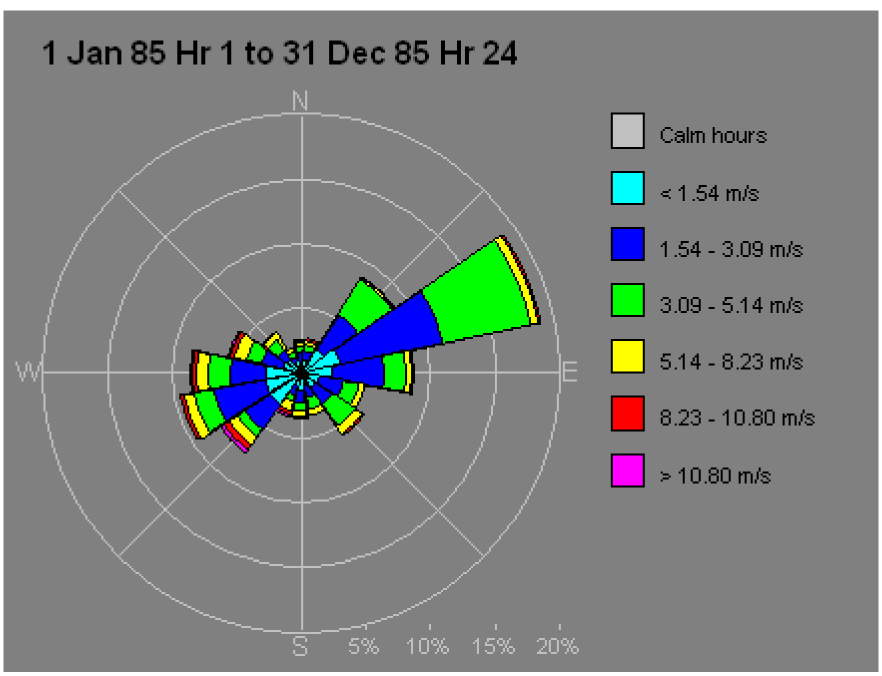


Figure 2**.** Wind Rose for 1985 Data Used in the Near-field Modeling for the Project.

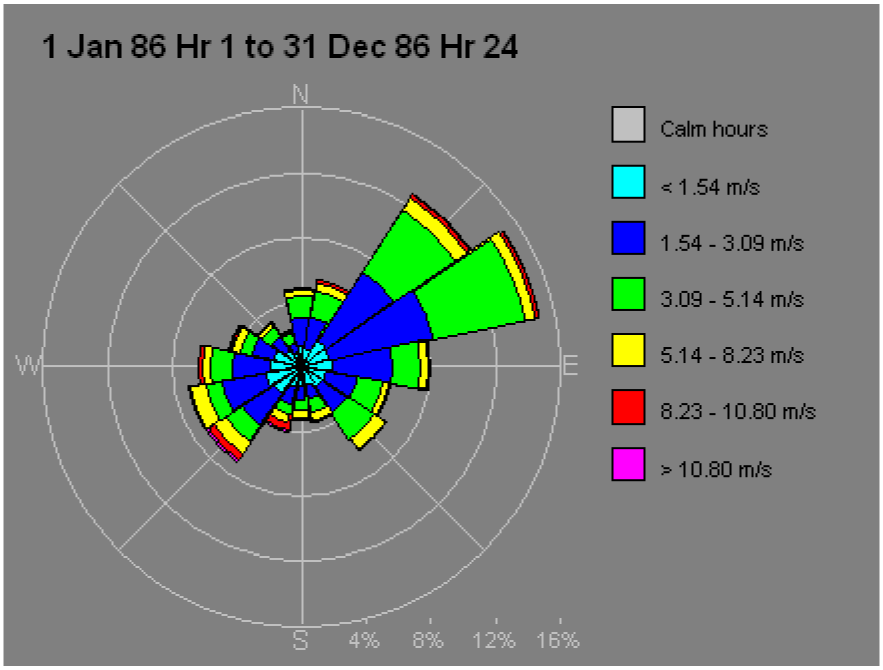


Figure 3**.** Wind Rose for 1986 Data Used in the Near-field Modeling for the Project.

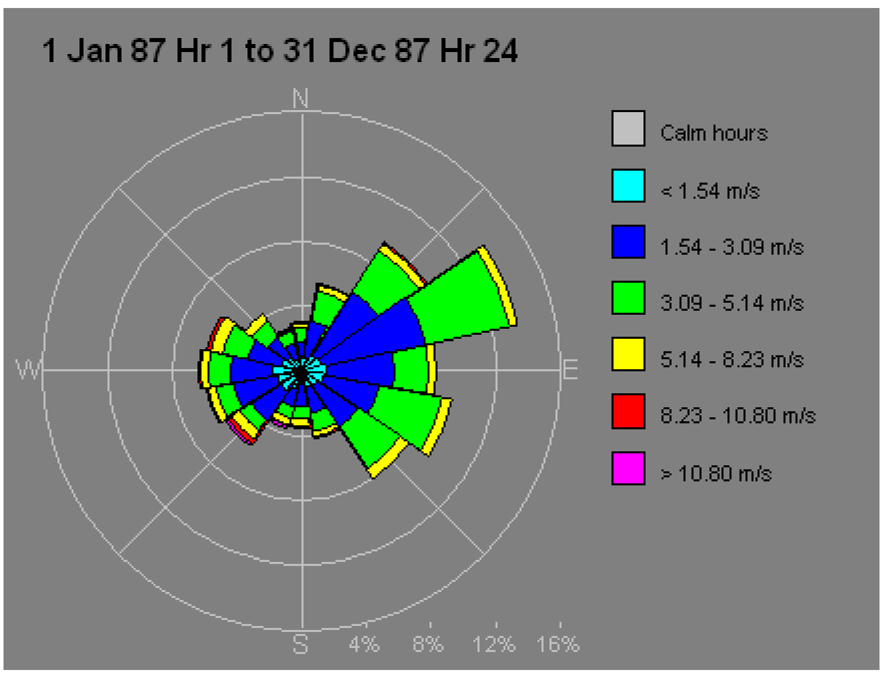


Figure 4**.** Wind Rose for 1987 Data Used in the Near-field Modeling for the Project.

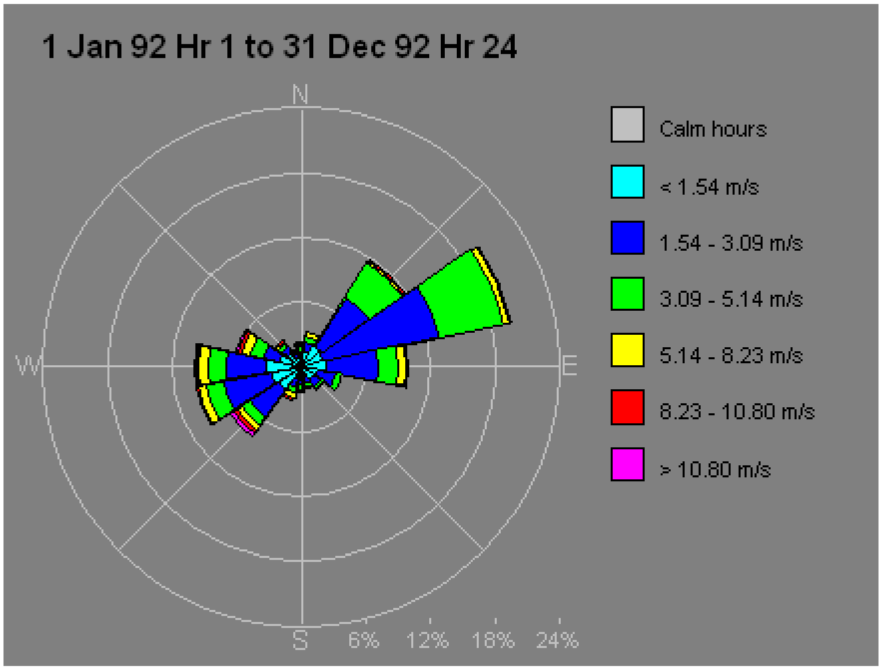


Figure 5. Wind Rose for 1992 Data Used in the Near-field Modeling for the Project.

3.3 BACKGROUND DATA

Background pollutant concentrations are used as an indicator of existing conditions in the region, and are assumed to include emissions from existing industrial emission sources in operation and from mobile, urban, biogenic, and other non-industrial emission sources. These background concentrations are added to modeled near-field Project impacts to calculate total ambient air quality impacts for comparisons with National and State Ambient Air Quality Standards (i.e., NAAQS and UAAQS).

Background values for criteria pollutants (PM_{10}, CO, NOx, and SO_2) were provided by Utah DEQ for each county in the Project Area that falls within the State of Utah. Because the Project lies within Duchesne County, background values for this County were used in the near-field analysis. A table of the background values used in the near-field modeling is shown in Table 6.

Table 6. Near-field Analysis Background Ambient Air Quality Concentration[1].

Pollutant	Averaging Period	Measured Background Concentration (µg/m^3)
Carbon monoxide (CO)	1-hour	1145
	8-hour	1145
Nitrogen dioxide (NO_2)	Annual	10
PM_{10}	24-hour	28
	Annual	10
$PM_{2.5}$	24-hour	27.6
	Annual	9.3
Sulfur dioxide (SO_2)	3-hour	20
	24-hour	10
	Annual	5

[1]Background data provided by Utah Department of Environmental Quality Division of Air Quality (DAQ) for Duchesne County. (D. Prey, DAQ, personal communication, 2010.)

Note: Ozone data were not provided by the DAQ because the monitoring network is extremely sparse in this area. The closest ozone data are for the Piceance Basin in Colorado where the measured 1-hour background concentration is 0.88 parts per million (ppm) and the 8-hour background concentration is 0.074 ppm (Colorado Department of Public Health and Environment 2008)
µg/m^3 = micrograms per cubic meter

3.4 CRITERIA POLLUTANT IMPACT ASSESSMENT

The near-field criteria pollutant impact assessment was performed to estimate maximum potential impacts of PM_{10}, $PM_{2.5}$, NO_2, SO_2, and CO from project emissions sources including well site and compressor station emissions. Maximum predicted concentrations in the vicinity of project emissions sources were compared with the Utah Air Quality Standards (UAAQS) and the National Ambient Air Quality Standards (NAAQS).

3.4.1 Construction Scenario

For the construction phase, a conservative scenario of maximum potential emissions was modeled. Since actual well pad locations and configurations are not yet known, the construction scenario was designed to produce a conservative but reasonable estimate of maximum emissions associated with well pad, compressor station, and haul road development. A central compressor station was located near a well pad and a haul road was placed in proximity to both.

Two receptor grids were utilized to assess impacts associated with the scenarios. The first was a fence-line grid that surrounded each source with a buffer of 50 m and a receptor spacing of 100 m. The second was a uniform Cartesian grid with 100 m x 100 m spacing extending from the fence-line grid to a distance of 50 km or a distance sufficient to assess all impacts.

Flat terrain was assumed for the modeling scenario as actual topography was not known. Figure 6 presents the modeled configuration. Area sources were used to represent emissions from the road and for pad and compressor construction areas. The compressor pad was assumed to be 1.5 acres in size and the well pad was approximated as 2.5 acres in size. The haul road was modeled as 35 feet wide to account for the added disturbed ground from pipeline construction and large construction vehicle traffic. In addition, a point source was used to represent the drilling and completion rigs and was placed in the center of the well pad.

Since specific stack parameters for the drill rig are not known, default parameters developed for the Atlantic Rim EIS (BLM, 2006) were used (Table 14). Since the eventual configuration of the sources and receptors and their orientation with respect to the prevailing wind direction is not known, the construction scenario was modeled 12 times, once at each of twelve 30º rotations. This ensured that impacts from all directional layout configurations and meteorological conditions were assessed.

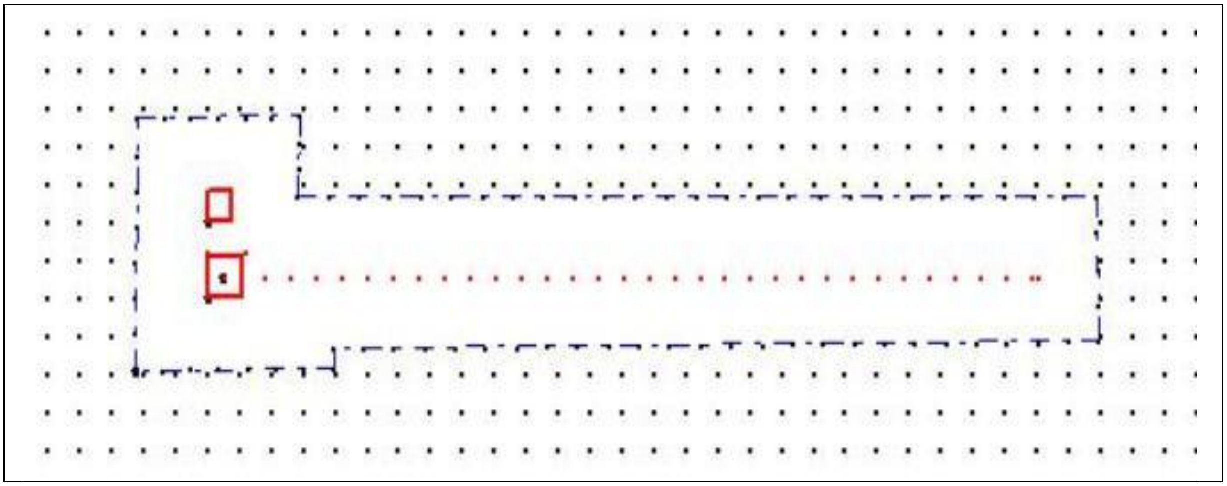


Figure 6**.** Receptor Grid and Source Locations for the Construction Phase (fence line in blue, red boxes and dots are locations of area and point sources).

3.4.2 Construction Emissions

Emissions for the construction scenario were developed using a method developed on previous Oil and Gas EIS projects in the Intermountain West. The development was completed using conservative assumptions about emissions associated with the processes involved in the construction of well and compressor pad, haul roads and the drilling and completion of a well. Three specifics bear mentioning with regard to the utilization of the final emission rates in ISCST3 for the construction scenario.

1. Drilling and completion were modeled separately in the construction scenario. Due to the procedures involved in drilling and completion the two processes do not occur simultaneously. In order to correctly model this fact, drilling and completion emissions were separated into two model runs. In each case, the emissions from drilling or completion were emitted from the point source at the center of the theoretical well pad.
2. Due to the emission factor limitations of ISCST3, wind-blown dust emissions could not be dynamically turned on and off depending on wind speeds. As a result, emissions for wind-blown dust had to be scaled to account for the amount of time that wind-blown erosion was likely to occur. This was accomplished by

determining the number of hours in each year's meteorological inputs that were above a threshold wind speed. For this analysis, the threshold was set at 11m/s which is consistent with other similar analyses (e.g., BLM 2007). The ratio of hours above the threshold was then calculated and the resultant ratio was applied to the emission rate. This provided an emission rate that approximated the emissions due to wind-blown dust and is determined by wind speed.

3. For the ISCST3 runs utilizing maximum short term emission rates, emissions from equipment and human operations were turned on and off depending on the hour of day. This was done to ensure that emissions accurately approximate work hour emissions for the construction scenarios.

3.4.3 Construction Results

After modeling was performed, maximum modeled concentrations were added to the representative background concentrations (Table 7) and compared with the UAAQS and NAAQS for criteria pollutants. For all criteria pollutants modeled, predicted total concentrations were lower than the UAAQS and NAAQS, indicating that no detrimental near-field impacts are expected from the construction phase of the Ashley project.

Based on new information obtained since the completion of the AQTSD in 2008, the UDEQ DAQ was able to recommend a $PM_{2.5}$ background value for the Project Area (ENVIRON 2010). The recommended background for 24-hour average 98% value $PM_{2.5}$ is 27.6 µg/m^3 and the annual average $PM_{2.5}$ value is 9.3 µg/m^3. UDEQ DAQ notes that the 24-hour average values of 27.6 µg/m^3 is a winter value and that winter values are much higher than non-winter values. These background values were used to model two construction scenarios (Table 3-9). Scenario A is a very conservative construction scenario where there is simultaneous construction of well pads, roads, and compressor stations, and all engines are fully deteriorated. In this scenario, 24-hour $PM_{2.5}$ is not in compliance with NAAQS. However, Scenario B uses a conservative, but more realistic, construction scenario where roads are built before well pad and compressor station construction begins and engines are approximately 40% deteriorated. In this scenario, the project complies with NAAQS criteria.

Since the completion of the AQTSD in 2008, the EPA has promulgated new NAAQSs for 1-hour NO_2 and 1-hour SO_2. The model used to evaluate 1-hour NO_2 and SO_2 was identical to the modeling reported in the AQTSD, which did not apply the air quality mitigation measures. Table 3-9 shows the highest 3-year average of the 98th percentile 1-hour NO_2 concentrations and the highest 3-year average of the 99th percentile 1-hour SO_2 concentrations, as required by the new primary standards.

Table 7. Maximum Modeled Construction Concentrations.

Pollutant	Averaging Time	Modeled Value µg/m³	Background Value µg/m³	Total Value µg/m³	UAAQS NAAQS µg/m³	Compliance
$PM_{2.5}$[1] Scenario A	24-hour	11.82	27.6	39.4	35	N
$PM_{2.5}$ Scenario A	annual	0.151	9.3	9.45	15	Y
$PM_{2.5}$ Scenario B	24-hour	6.57	27.6	34.12	35	Y
$PM_{2.5}$ Scenario B	annual	0.151	9.3	9.45	15	Y
PM_{10}[3]	24-hour	35.06	28	63.06	150	Y
PM_{10}	annual	1.39	10	11.39	50	Y
NO_x	annual	0.36	10	10.36	100	Y
NO_2	1-hour	7.70	75.3	83.1	188	Y
CO[2]	1-hour	458.00	1	459.00	40,000	Y
CO[2]	8-hour	323.63	1	324.63	10,000	Y
SO_2	1-hour	0.6	99	99.6	197	Y
SO_2[2]	3-hour	0.60	20	20.60	1300	Y
SO_2[2]	24-hour	0.16	10	10.16	365	Y
SO_2	annual	0.002	5	5.002	80	Y

[1] 8th high for each year was used to calculate a three-year running average, the maximum three average is reported.
[2] Second highest value was used because the value is not to be exceeded more than once per year.
[3] Fourth highest value for three-year modeling period.
µg/m³ = micrograms per cubic meter
CO = carbon monoxide
NO_x = nitrogen oxide
PM = particulate matter
SO_2 = sulfur dioxide

3.4.4 Production Scenario

As with the construction phase, the actual configuration of the production sites is not known; therefore, a conservative but reasonable production scenario was developed. An assessment of the maximum impacts associated with production emissions sources was performed.

Modeling analyses were performed to estimate conservative near-field criteria pollutant concentrations for a scenario with maximum production. Based on maximum well density information provided by the Proponent, the well spacing in the maximum production scenario was set to one well for every 40 acres or 16 wells per square mile. Figure 7 represents the proposed modeling set up for the production phase.

For this scenario, a representative modeling area of one square mile was used with a central compressor station in the center of 16 well pads. The central compressor was modeled as a point source while all other well production activities (heaters, traffic, artificial lift engines, tank losses, fugitive emissions, etc.) were modeled as area sources (red squares in Figure 3-7). Emissions associated with truck tail pipe emissions and fugitive dust from haul roads were modeled as area sources located between the well pad locations (red lines in Figure 3-7). As with the construction phase simulation, the compressor pad was approximately 1.5 acres in size and the well pads was approximately 2.5 acres in size. The haul roads were modeled as 22 feet wide to account for the reduced width of a completed road bed.

Two receptor grids were used to assess impacts associated with this scenario. The first was a fence-line grid that surrounded each source with a buffer of 50 m and a receptor spacing of 100 m. The second is a uniform Cartesian grid with 100 m x 100 m spacing extending from the fence-line grid to a distance of 50 km or the distance needed to ensure all impacts were captured.

As with the construction phase, this scenario was modeled in rotational segments to assess the maximum impacts. However, due to symmetry in the set-up 5 unique rotations were modeled at 0, 30, 60, 120 and 150 degrees relative to the prevailing wind direction.

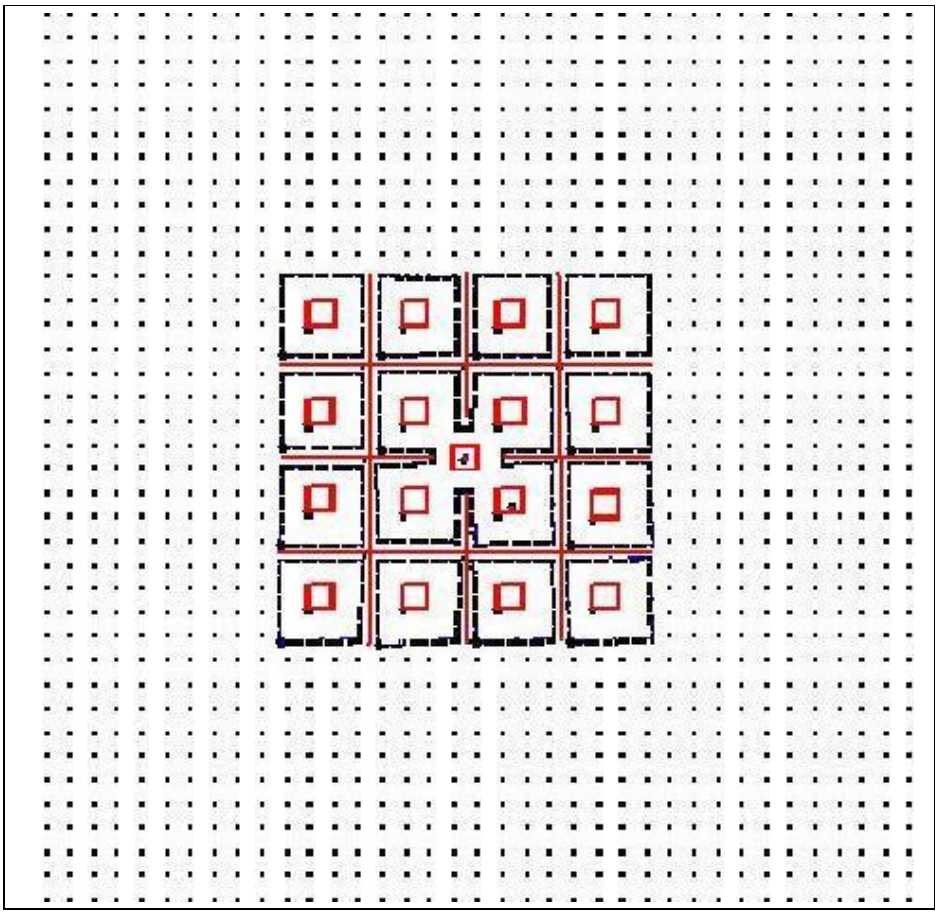


Figure 7**.** Representative Receptor Grid and Production Field Set up for Maximum Production Scenario.

3.4.5 Production Emissions

Three specific issues in the development of the production emissions bear mentioning with regard to the modeling of the final emission rates in ISCST3.

1. For the modeled production scenarios using maximum short term emission rates, emissions from equipment and human operations were turned on and off depending on the hour of day. This was done to ensure that emissions accurately approximate work hour emissions for the production scenarios.
2. Emissions associated with vehicle traffic were calculated using the average distance a vehicle would have to travel once they entered the production field. This was determined by taking the shortest and the longest road segments in the production modeling scenario and taking an arithmetic average of the two. This distance was then doubled to determine the round trip vehicle miles travel. This value was then used to calculate vehicle emissions.
3. Due to the emission factor limitations of ISCST3, windblown dust emissions could not be dynamically turned on and off depending on wind speeds. As a result, emissions for wind blown dust had to be scaled to account for the amount of time that wind blown erosion was likely to occur. This was accomplished by determining the number of hours in each year's meteorological inputs that were above a threshold wind speed. For this analysis the threshold was set at 11 m/s, which is consistent with other similar analyses. The ratio of hours above the threshold was then calculated and the resultant ratio was applied to the emission rate. This provided an emission rate that approximated the emissions due to wind blown dust and limited by wind speed.

3.4.6 Production Results

The ISCST3 model was used to predict maximum impacts for modeled scenario. Maximum predicted pollutant concentrations are given in Table 8. For all criteria pollutants modeled, predicted total concentrations were lower than the UAAQS and NAAQS, indicating that no detrimental near-field impacts are expected from the production phase of the Ashley project.

Table 7. Maximum Modeled Production Concentrations, Ashley Berry Project.

Pollutant	Averaging Time	Modeled Value ug/m^3	Background Value ug/m3	Total Value ug/m3	UAAQS NAAQS ug/m^3	Compliance
$PM_{2.5}$[1]	24 hr	6.57	27.6	34.12	35	Yes
$PM_{2.5}$	annual	0.151	9.3	9.45	15	Yes
PM_{10}[3]	24 hr	19.41	28	47.41	150	Yes
PM_{10}	annual	22.68	10	32.68	50	Yes
NO_x	annual	7.30	10	17.30	100	Yes
NO_2	1 hr	71.7	75.3	147.0	188	Yes
CO[2]	1 hr	78.55	1	79.55	40,000	Yes
CO[2]	8 hr	45.70	1	46.70	10,000	Yes
SO_2	1 hr	0.2	99	99.2	197	Yes
SO_2	3 hr	0.13	20	20.13	1300	Yes
SO_2	24 hr	0.047	10	10.05	365	Yes
SO_2	annual	0.043	5	5.04	80	Yes

[1] 8^{th} high for each year was used to calculate a three-year running average, the maximum three average is reported.
[2] Second highest value was used because the value is not to be exceeded more than once per year.
[3] Fourth highest value for three-year modeling period.
µg/m^3 = micrograms per cubic meter
CO = carbon monoxide
NO_x = nitrogen oxide
PM = particulate matter
SO_2 = sulfur dioxide

3.5 HAP IMPACT ASSESSMENT

Near-field Hazardous Air Pollutants (HAPs) concentrations were calculated for assessing impacts in the immediate vicinity of the Project area emission sources for both short-term (acute) exposure assessment and at greater distances for calculation of long-term risk. HAPs emissions included those from well-site fugitives, ancillary facilities, and natural gas combustion and dehydration at compressor stations. Because HAPs will be emitted predominantly during the production phase, only HAP emissions from the production scenario were analyzed.

The modeling methodology for the short-term and long-term HAP impact assessments is nearly identical to the methodology outlined in Section 3.4. Area sources were used for modeling well-site fugitive HAP emissions during production, and point sources were used to represent compressor engines and processing facility stack emissions. The maximum emissions case was developed for each HAP and was modeled.

Receptors were placed 50 m from production wells at 100 m spacing. Receptors were also placed at 100 m intervals along compressor/processing facility fence lines.

Short-term HAP concentrations were then compared to the Toxic Screening Level (TSLs). The TSLs are shown in Table 9 and were provided by the State of Utah's Division of Air Quality. The Toxic Screening Level defines a concentration at or below which no adverse health effects are expected. The TSLs are defined for a given averaging period which is also shown below in Table 9.

Long-term exposures to HAPs emitted by the Proposed Project were compared to Reference Concentrations for Chronic Inhalation (RfCs). An RfC is defined by EPA as the daily inhalation concentration at which no long-term adverse health effects are expected. RfCs exist for both non-carcinogenic and carcinogenic effects on human health (EPA, 2005c). Annual modeled HAP concentrations for all HAPs emitted were compared directly to the non-carcinogenic RfCs and are summarized in Table 9. For all HAPs, the modeled concentrations are below the applicable RfCs and TSLs, indicating that no short term or long term adverse health effects from exposure to HAPs are expected from the Ashley Project.

Table 8. Maximum Modeled HAP Concentrations, Ashley Project.

Pollutant	Averaging Time	Max Modeled Value ug/m^3	Non-Carcinogenic RfC [1] (μg/m^3)	TSL (μg/m^3)	Compliance
Benzene	24 hr	11.02		53.3	Yes
Benzene	Annual	2.20	30		Yes
Ethylbenzene	24 hr	0.98		14466.7	Yes
Ethylbenzene	Annual	0.252	1,000		Yes
Formaldehyde	1 hr	1.95		37	Yes
Formaldehyde	Annual	0.14	9.8		Yes
N-Hexane	24 hr	17.54		5875	Yes
N-Hexane	Annual	3.51	200		Yes
Toluene	24 hr	13.65		2512.1.	Yes
Toluene	Annual	3.40	400		Yes
Xylene	24 hr	6.56		14466.7	Yes
Xylene	Annual	1.78	100		Yes

EPA Air Toxics Database, Table 1 (EPA, 2010). μg/m^3 = micrograms per cubic meter

Finally, long-term exposures to emissions of suspected carcinogens (benzene and formaldehyde) were evaluated based on estimates of the increased latent cancer risk over a 70-year lifetime. This analysis presents the potential incremental risk from these pollutants, and does not represent a total risk analysis. The cancer risks were calculated using the maximum predicted annual concentrations and EPA's chronic inhalation unit risk factors (URF) for carcinogenic constituents.

Estimated cancer risks were evaluated based on the Superfund National Oil and Hazardous Substances Pollution Contingency Plan (EPA 1993), where a cancer risk range of $1x10^{-6}$ to $1x10^{-4}$ is generally acceptable. Two estimates of cancer risk are presented: 1) a most likely exposure (MLE) scenario; and 2) a maximum exposed individual (MEI) scenario. The estimated cancer risks are adjusted to account for duration of exposure and time spent at home.

The adjustment for the MLE scenario is assumed to be 9 years, which corresponds to the mean duration that a family remains at a residence (EPA 1993). This duration corresponds to an adjustment factor of 9/70 = 0.13. The duration of exposure for the MEI scenario is assumed to be 50 years (i.e., the LOF), corresponding to an adjustment factor of 50/70 = 0.71. A second adjustment is made for time spent at home versus time spent elsewhere. For the MLE scenario, the at-home time fraction is 0.64 (EPA 1993), and it is assumed that during the rest of the day the individual would remain in an area where annual HAP concentrations would be one quarter as large as the maximum annual average concentration. Therefore, the final MLE adjustment factor is (0.13) x [(0.64 x 1.0) + (0.36 x 0.25)] = 0.0949. The MEI scenario assumes that the individual is at home 100% of the time, for a final MEI adjustment factor of (0.71 x 1.0) = 0.71.

For each constituent, the cancer risk was computed by multiplying the maximum predicted annual concentration by the URF and by the overall exposure adjustment factor. The cancer risks for both constituents were then summed to provide an estimate of the total inhalation cancer risk.

The modeled long-term risks from benzene and formaldehyde are shown in Table 10. The maximum predicted formaldehyde concentration representative of cumulative impacts was used. Under the MLE scenario, the estimated cancer risk associated with long-term exposure to benzene and formaldehyde is below $1x10^{-6}$ for all cases. Under the MEI analyses, for each modeling scenario, the incremental risk for formaldehyde is less than $1x10^{-6}$, and both the incremental risk for benzene and the combined incremental risk fall on the lower end of the cancer risk range of $1x10^{-6}$ to $1x10^{-4}$.

Table 9**.** Long-term Modeled MLE and MEI Cancer Risk Analyses, Ashley Berry Project.

Pollutant	Averaging Time	Modeled Value ug/m^3	Unit Risk Value ug/m^3	Exposure Adjustment MLE ug/m^3	Exposure Adjustment MEI ug/m^3	Cancer Risk MLE	Cancer Risk MEI
Benzene	Annual	2.20	7.8E-06	0.0949	0.86	1.63E-6	1.48E-5
Formaldehyde	Annual	0.14	1.3E-05	0.0949	0.86	1.73E-7	1.56E-6

[1] MLE = most likely exposure; MEI = maximally exposed individual.
[2] EPA Air Toxics Database, Table 1 (EPA, 2005c).

Total risk is calculated here; however, the additive effects of multiple chemicals are not fully understood and this should be taken into account when viewing these results.

4.0 FAR-FIELD ANALYSES

The purpose of the Ashley CALPUFF far-field analyses is to quantify potential air quality (AQ) and air quality related values (AQRVs) impacts at Class I and sensitive Class II areas due to the Project as well as other Oil and Gas (O&G) production in the Uinta Basin and surrounding regions. Air pollutant emissions of NOx, SO_2, PM_{10}, and $PM_{2.5}$ were modeled using the CALMET/CALPUFF modeling system to predict AQ and AQRV impacts at far-field PSD Class I and sensitive Class II areas. The Class I and sensitive Class II receptor areas analyzed in the far-field modeling were:

- Bryce Canyon National Park, Utah (Class I);

- Capitol Reef National Park, Utah (Class I);
- Canyonlands National Park, Utah (Class I);
- Arches National Park, Utah (Class I); and
- Black Canyon of the Gunnison National Park, Colorado (Class I);
- Maroon Bells-Snowmass Wilderness Area, Colorado (Class I);
- West Elk Wilderness Area, Colorado (Class I);
- Flat Tops Wilderness Area, Colorado (Class I);
- Flaming Gorge National Recreation Area, Utah (Class II);
- High Uinta Wilderness Area, Utah (Class II);
- Brown Park NWR, Utah (Class II);
- Dinosaur National Monument, Utah (Class II);
- Colorado National Monument, Colorado (Class II);
- Holy Cross Wilderness Area, Colorado (Class II);
- Raggeds Wilderness Area, Colorado (Class II); and
- Hunter Frying Pan Wilderness Area, Colorado (Class II).

Predicted pollutant concentrations at these areas were compared to applicable national and state ambient air quality standards and PSD Class I and Class II increments and were used to assess potential impacts to AQRVs, which include visibility (regional haze) and acid (sulfur and nitrogen) deposition. In addition, analyses were performed for lakes designated as acid sensitive located within Class I and Class II areas to assess potential lake acidification from acid deposition impacts. The U.S. Forest Service provided a list of sensitive lakes to be analyzed:

- Walkup Lake, Utah;
- Dean Lake, Utah;
- Fish Lake, Utah;
- Bluebell Lake, Utah;
- No Name Lake, Utah.

4.1 MODELING METHODOLOGY

The far-field ambient air quality and AQRV impact assessment was performed to quantify the potential maximum pollutant impacts at Class I areas and sensitive Class II areas in the vicinity of the Project Area resulting from construction, drilling and production emissions. The study was performed in accordance with the following recent guidance sources:

- Direct guidance provided by representatives of the BLM, USEPA, UDAQ, USFWS, NPS, Forest Service, etc.;
- Guideline on Air Quality Models, 40 Code of Federal Regulations (C.F.R.), Part 51, Appendix W;
- Interagency Work Group on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, Office of Air Quality Planning and Standards, December 1998 (IWAQM 1998);
- Federal Land Managers - Air Quality Related Values Workgroup (FLAG), Phase I Report, December 2000 (FLAG 2000); and

- Memorandum from EPA on the regulatory default settings for CALPUFF modeling (Atkinson and Fox, 2006).

A Modeling Protocol was prepared prior to conducting the analyses (ENVIRON, 2008) and distributed for stakeholder review. The procedures in the Modeling Protocol were followed in the far-field modeling analyses. As stated in the Modeling Protocol, the EPA-recommended regulatory version 5.8 of the CALPUFF/CALMET modeling system was used to generate meteorological fields and calculate ambient concentrations and AQRV impacts for three years: 2002, 2005, and 2006.

The CALMET/CALPUFF modeling domain used in the far-field modeling is shown in Figure 8, along with the locations of the surface and upper-air meteorological and surface precipitation sites within and near the modeling domain. The CALMET meteorological model was run using meteorological data generated by the MM5 meteorological model, combined with the surface, upper-air, and precipitation data.

Air emissions of NO_x, SO_2, PM_{10}, and $PM_{2.5}$ from production wells, construction, drilling and compressors for the Project and cumulative emissions from other sources, including all currently operating, proposed, and Reasonably Foreseeable Development (RFD) emissions sources within the modeling domain, were modeled. At the request of the Forest Service, air emissions of $PM_{2.5}$ from Ashley Project combustion sources were further speciated into filterable and condensable PM, and then into elemental carbon and secondary aerosol as in the West Tavaputs EIS (Buys and Associates, 2007). A description of the emissions inventory procedures is given in Section 2 of this AQTSD with the detailed inventory provided in Appendix A (Ashley Project emission inventory) and Appendix B (cumulative emission inventory). The processing of these emissions sources for input to the CALPUFF model is described in Section 4.4.4.

CALPUFF output was post-processed with POSTUTIL and CALPOST to estimate: (1) concentrations for comparison to ambient standards and Class I and II PSD Increments; (2) wet and dry deposition amounts for comparison to sulfur (S) and nitrogen (N) deposition thresholds and to calculate acid neutralizing capacity (ANC) for sensitive water bodies; and (3) light extinction for comparison to visibility impact thresholds in Class I and sensitive Class II areas. A discussion of the post-processing methodology is provided in Section 4.5.

4.2 PROJECT MODELING SCENARIOS

Multiple CALPUFF emissions scenarios were performed using meteorological data for three years (2002, 2005 and 2006). CALMET meteorological inputs were developed using hourly, gridded three-dimensional 12 km MM5 data as well as surface and upper-air meteorological and surface precipitation observation data for 2002, 2005, and 2006. The emissions scenario conservatively assumes that both production emissions (producing well sites and operational ancillary equipment including compressor stations) and construction emissions (drill rigs and associated traffic) occur simultaneously throughout the year. The emissions used to develop these field-wide scenarios are described briefly in Section 2 and in detail in Appendix A.

4.3 METEOROLOGICAL MODEL INPUT AND OPTIONS

CALMET was used to develop wind fields and other meteorological data for the study area within the modeling domain given in Figures 8 and 9 and three years: 2002, 2005 and 2006.

4.3.1 CALMET Geophysical and Meteorological Input Data

The CALMET modeling incorporated regional mesoscale meteorological (MM5) model output fields at 12 km resolution and data from additional surface meteorological stations, precipitation stations, and upper-air meteorological stations. The locations of the meteorological stations are shown in Figure 8.

The uniform horizontal grid was processed to 4 km resolution using a Lambert Conformal Conical (LCC) projection defined with a central longitude/latitude at (-97°, 40°) and first and second latitude parallels at 33° and 45°. The modeling domain had a southwest corner origin of (-1392 km, -228 km) and consisted of 156 by 117 4 km grid cells, and covered the project area and Class I areas and other sensitive Class II areas. Eleven vertical layers were specified with layer interfaces at 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 4500 m above ground level (AGL).

12 km MM5 data were used as input to CALMET and were used as the initial guess field (IPROG=14). CALMET then performed a Step 1 procedure that included accounting for diagnostic wind model effects using the 4 km terrain and land use data to simulate blocking and deflection, channeling, slope flows, etc. 12 km MM5 data were available for 2002, 2005, and 2006. For 2002, ENVIRON performed a 12 km MM5 simulation for the Western Regional Air Partnership (WRAP) in support of regional haze modeling in the western U.S. (Kemball-Cook et. al. 2004). For 2005, 36 km and 12 km MM5 data were developed by Alpine Geophysics and ENVIRON for the New Mexico Environmental Department and used in the Four Corners Air Quality Task Force Study. For 2006, 36 km and 12 km MM5 data were developed by ENVIRON for the Denver 8-hour Ozone SIP (Morris et al., 2007) and the BLM Continental Divide-Creston EIS (Sage Consulting and ENVIRON, 2007).

In Step 2 of the CALMET modeling, CALMET incorporated the surface and upper-air meteorological observations in the Step 1 wind fields. Locations of the surface and upper-air meteorological stations and surface precipitation stations used in the analysis are shown in Figure 8.

USGS 1:250,000-Scale Land Use and Land Cover (LULC) data, and USGS 1-degree DEM data were used for land use and terrain data in the development of the CALMET wind fields.

4.3.2 CALMET Modeling Options

The CALMET modeling system has numerous options that need to be specified. These options were defined following EPA-recommended regulatory default options as given by Atkinson and Fox (2006), with some exceptions explained below. Table 11 lists the EPA-recommended regulatory default options and the option definitions used in this study, deviations from EPA-recommended defaults are indicated by bold in Table 11 and are as follows:

- The EPA-recommended default is to not use any MM5 data (IPROG=0), whereas for the Project's CALMET modeling 12 km MM5 data was specified as input for all three years of modeling (IPROG=14). Use of MM5 data is believed to produce more representative CALMET meteorological fields and is encouraged by FLMS and EPA.
- The maximum mixing height for the Project's MM5 modeling is higher (4,500 m AGL) than the EPA-recommended regulatory default value (3,000 m AGL). Although a 3,000 m AGL maximum mixing height may be appropriate for the eastern U.S., mixing heights are higher in the western U.S. In their CALPUFF BART Modeling Protocol, the Colorado Department of Health and Environment (2005) present evidence that higher mixing heights are needed in the west so a maximum mixing height consistent with their findings was adopted for this study.
- Because CALMET uses MM5 input data, IEXTRP was set to 1 to keep surface winds from being extrapolated to upper levels. The EPA recommended default (-4) is to extrapolate the surface wind observations aloft using similarity theory which makes more sense if there is no MM5 data available as in the EPA default.

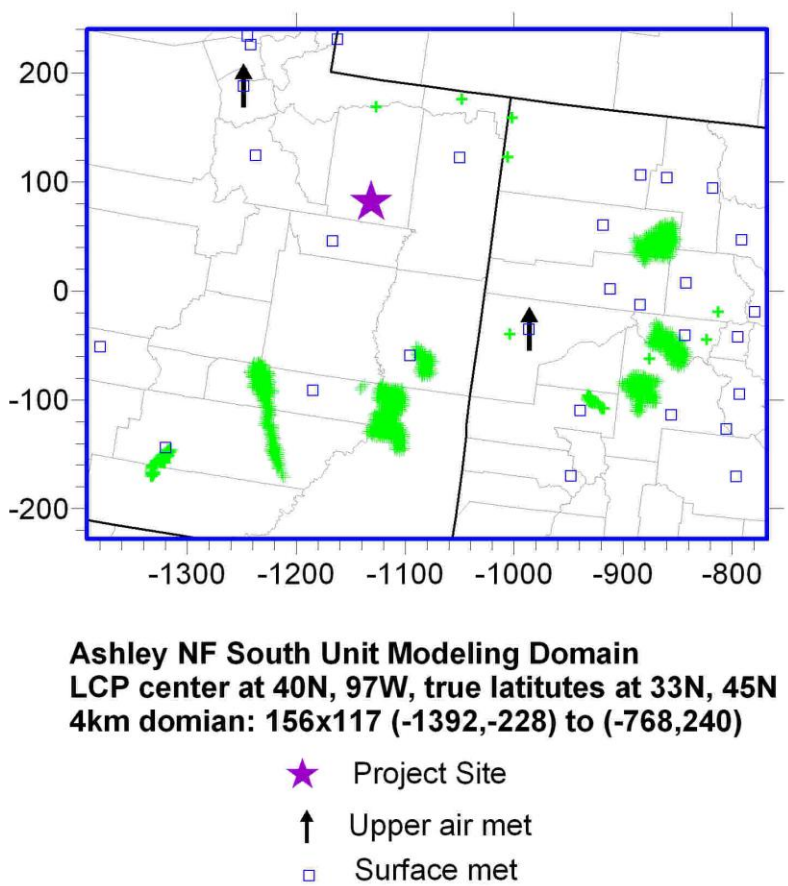


Figure 8. Ashley CALPUFF Modeling Domain with Class I and II Area Receptor Locations and Locations of Surface and Upper-air Meteorological Sites.

Table 10**.** CALMET Options to be Used in the Ashley far-field CALMET/CALPUFF Modeling and Comparison with EPA Regulatory Default Settings as Given by Atkinson and Fox (2006) (deviations from EPA recommended defaults are indicated by **bold text**.).

Variable	Description	EPA Default	Project Values
GEO.DAT	Name of Geophysical data file	GEO.DAT	GEO.DAT
SURF.DAT	Name of Surface data file	SURF.DAT	SURF.DAT
PRECIP.DAT	Name of Precipitation data file	PRECIP.DAT	PRECIP.DAT
NUSTA	Number of upper air data sites	User Defined	10
UPN.DAT	Names of NUSTA upper air data files	UPN.DAT	UPN.DAT
IBYR	Beginning year	User Defines	User Defines
IBMO	Beginning month	User Defines	User Defines
IBDY	Beginning day	User Defines	User Defines
IBHR	Beginning hour	User Defines	User Defines
IBTZ	Base time zone	User Defines	User Defines
IRLG	Number of hours to simulate	User Defines	User Defines
IRTYPE	Output file type to create (must be 1 for CALPUFF)	1	1
LCALGRD	Are w-components and temperature needed?	T	T
NX	Number of east-west grid cells	*User Defines*	*127*
NY	Number of north-south grid cells	User Defines	152
DGRIDKM	Grid spacing	User Defines	4 km
XORIGKM	Southwest grid cell X coordinate	User Defines	-1,180.0.
YORIGKM	Southwest grid cell Y coordinate	User Defines	-64.
IUTMZN	UTM Zone	User Defines	NA
LLCONF	When using Lambert Conformal map coordinates, rotate winds from true north to map north?	F	F
XLAT1	Latitude of 1st standard parallel	**30**	**33.**
XLAT2	Latitude of 2nd standard parallel	**60**	**45.**
RLON0	Longitude used if LLCONF = T	**90**	**-97.**
RLAT0	Latitude used if LLCONF = T	**40**	**40.**
NZ	Number of vertical Layers	User Defines	11

Variable	Description	EPA Default	Project Values
ZFACE	Vertical cell face heights (NZ+1 values)	User Defines	0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 4500
LSAVE	Save met. Data fields in an unformatted file?	T	T
IFORMO	Format of unformatted file (1 for CALPUFF)	1	1
NSSTA	Number of stations in SURF.DAT file	User Defines	13
NPSTA	Number of stations in PRECIP.DAT	User Defines	64
ICLOUD	Is cloud data to be input as gridded fields? 0=No)	0	0
IFORMS	Format of surface data (2 = formatted)	2	2
IFORMP	Format of precipitation data (2= formatted)	2	2
IFORMC	Format of cloud data (2= formatted)	2	2
IWFCOD	Generate winds by diagnostic wind module? (1 = Yes)	1	1
IFRADJ	Adjust winds using Froude number effects? (1= Yes)	1	1
IKINE	Adjust winds using Kinematic effects? (1 = Yes)	0	0
IOBR	Use O'Brien procedure for vertical winds? (0 = No)	0	0
ISLOPE	Compute slope flows? (1 = Yes)	1	1
IEXTRP	Extrapolate surface winds to upper layers? (-4 = use similarity theory and ignore layer 1 of upper air station data; =1 no vertical extrapolation of surface winds)	**-4**	**1**
ICALM	Extrapolate surface calms to upper layers? (0 = No)	0	0
BIAS	Surface/upper-air weighting factors (NZ values)	NZ*0	NZ*0
IPROG	Using prognostic or MM-FDDA data? (0 = No)	**0**	**14**
LVARY	Use varying radius to develop surface winds?	*F*	*F*
RMAX1	Max surface over-land extrapolation radius (km)	User Defines	30.
RMAX2	Max aloft over-land extrapolations radius (km)	User Defines	60.
RMAX3	Maximum over-water extrapolation radius (km)	User Defines	60.
RMIN	Minimum extrapolation radius (km)	0.1	0.1
RMIN2	Distance (km) around an upper air site where vertical extrapolation is excluded (Set to –1 if IEXTRP = ±4)	4	4
TERRAD	Radius of influence of terrain features (km)	*User Defines*	10.
R1	Relative weight at surface of Step 1 field and obs	User Defines	6.0

Variable	Description	EPA Default	Project Values
R2	Relative weight aloft of Step 1 field and obs	User Defines	12.0
DIVLIM	Maximum acceptable divergence	5.E-6	5.E-6
NITER	Max number of passes in divergence minimization	50	50
NSMTH	Number of passes in smoothing (NZ values)	2,4*(NZ-1)	2,4*(NZ-1)
NINTR2	Max number of stations for interpolations (NA values)	99	99
CRITFN	Critical Froude number	1	1
ALPHA	Empirical factor triggering kinematic effects	0.1	0.1
IDIOPT1	Compute temperatures from observations (0 = True)	0	0
ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	User Defines	1
IDIOPT2	Compute domain-average lapse rates? (0 = True)	0	0
IUPT	Station for lapse rates (between 1 and NUSTA)	*User Defines*	1
ZUPT	Depth of domain-average lapse rate (m)	200	200
IDIOPT3	Compute internally initial guess winds? (0 = True)	0	0
IUPWND	Upper air station for domain winds (-1 = 1/r**2 interpolation of all stations)	-1	-1
ZUPWND	Bottom and top of layer for 1st guess winds (m)	1,1000	1,1000
IDIOPT4	Read surface winds from SURF.DAT? (0 = True)	0	0
IDIOPT5	Read aloft winds from UPn.DAT? (0 = True)	0	0
CONSTB	Neutral mixing height B constant	1.41	1.41
CONSTE	Convective mixing height E constant	0.15	0.15
CONSTN	Stable mixing height N constant	2400	2400
CONSTW	Over-water mixing height W constant	0.16	0.16
FCORIOL	Absolute value of Carioles parameter	1.E-4	1.E-4
IAVEZI	Spatial averaging of mixing heights? (1 = True)	1	1
MNMDAV	Max averaging radius (number of grid cells)	1	1
HAFANG	Half-angle for looking upwind (degrees)	30	30
ILEVZI	Layer to use in upwind averaging (between 1 and NZ)	1	1
DPTMIN	Minimum capping potential temperature lapse rate	0.001	0.001
DZZI	Depth for computing capping lapse rate (m)	200	200
ZIMIN	Minimum over-land mixing height (m)	50	50
ZIMAX	Maximum over-land mixing height (m)	**3000**	**4500**

Variable	Description	EPA Default	Project Values
ZIMINW	Minimum over-water mixing height (m)	50	50
ZIMAXW	Maximum over-water mixing height (m)	**3000**	**4500**
IRAD	Form of temperature interpolation (1 = 1/r)	1	1
TRADKM	Radius of temperature interpolation (km)	500	500
NUMTS	Max number of stations in temperature interpolations	5	5
IAVET	Conduct spatial averaging of temperature? (1 = True)	**1**	**0**
TGDEFB	Default over-water mixed layer lapse rate (K/m)	-0.0098	-0.0098
TGDEFA	Default over-water capping lapse rate (K/m)	-0.0045	-0.0045
JWAT1	Beginning land use type defining water	999	999
JWAT2	Ending land use type defining water	999	999
NFLAGP	Method for precipitation interpolation (2= 1/r**2)	2	2
SIGMAP	Precip radius for interpolations (km)	100	100
CUTP	Minimum cut off precip rate (mm/hr)	0.01	0.01
SSn	NSSTA input records for surface stations	User Defines	13
Usn	NUSTA input records for upper-air stations	User Defines	10
PSn	NPSTA input records for precipitations stations	User Defines	64
GEO.DAT	Name of Geophysical data file	GEO.DAT	GEO.DAT
SURF.DAT	Name of Surface data file	SURF.DAT	SURF.DAT
PRECIP.DAT	Name of Precipitation data file	PRECIP.DAT	PRECIP.DAT
NUSTA	Number of upper air data sites	User Defined	10
UPN.DAT	Names of NUSTA upper air data files	UPN.DAT	UPN.DAT
IBYR	Beginning year	User Defines	User Defines
IBMO	Beginning month	User Defines	User Defines
IBDY	Beginning day	User Defines	User Defines
IBHR	Beginning hour	User Defines	User Defines
IBTZ	Base time zone	User Defines	User Defines
IRLG	Number of hours to simulate	User Defines	User Defines
IRTYPE	Output file type to create (must be 1 for CALPUFF)	1	1
LCALGRD	Are w-components and temperature needed?	T	T
NX	Number of east-west grid cells	User Defines	127

Variable	Description	EPA Default	Project Values
NY	Number of north-south grid cells	User Defines	152
DGRIDKM	Grid spacing	User Defines	4 km
XORIGKM	Southwest grid cell X coordinate	User Defines	-1,180.0.
YORIGKM	Southwest grid cell Y coordinate	User Defines	-64.
IUTMZN	UTM Zone	User Defines	NA
LLCONF	When using Lambert Conformal map coordinates, rotate winds from true north to map north?	F	F
XLAT1	Latitude of 1st standard parallel	30	33.
XLAT2	Latitude of 2nd standard parallel	60	45.
RLON0	Longitude used if LLCONF = T	90	-97.
RLAT0	Latitude used if LLCONF = T	40	40.
NZ	Number of vertical Layers	User Defines	11
ZFACE	Vertical cell face heights (NZ+1 values)	User Defines	0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 4500
LSAVE	Save met. Data fields in an unformatted file?	T	T
IFORMO	Format of unformatted file (1 for CALPUFF)	1	1
NSSTA	Number of stations in SURF.DAT file	User Defines	13
NPSTA	Number of stations in PRECIP.DAT	User Defines	64
ICLOUD	Is cloud data to be input as gridded fields? 0=No)	0	0
IFORMS	Format of surface data (2 = formatted)	2	2
IFORMP	Format of precipitation data (2= formatted)	2	2
IFORMC	Format of cloud data (2= formatted)	2	2
IWFCOD	Generate winds by diagnostic wind module? (1 = Yes)	1	1
IFRADJ	Adjust winds using Froude number effects? (1= Yes)	1	1
IKINE	Adjust winds using Kinematic effects? (1 = Yes)	0	0
IOBR	Use O'Brien procedure for vertical winds? (0 = No)	0	0
ISLOPE	Compute slope flows? (1 = Yes)	1	1
IEXTRP	Extrapolate surface winds to upper layers? (-4 = use similarity theory and ignore layer 1 of upper air station data; =1 no vertical extrapolation of surface winds)	-4	1

Variable	Description	EPA Default	Project Values
ICALM	Extrapolate surface calms to upper layers? (0 = No)	0	0
BIAS	Surface/upper-air weighting factors (NZ values)	NZ*0	NZ*0
IPROG	Using prognostic or MM-FDDA data? (0 = No)	0	14
LVARY	Use varying radius to develop surface winds?	F	F
RMAX1	Max surface over-land extrapolation radius (km)	User Defines	30.
RMAX2	Max aloft over-land extrapolations radius (km)	User Defines	60.
RMAX3	Maximum over-water extrapolation radius (km)	User Defines	60.
RMIN	Minimum extrapolation radius (km)	0.1	0.1
RMIN2	Distance (km) around an upper air site where vertical extrapolation is excluded (Set to –1 if IEXTRP = ±4)	4	4
TERRAD	Radius of influence of terrain features (km)	User Defines	10.
R1	Relative weight at surface of Step 1 field and obs	User Defines	6.0
R2	Relative weight aloft of Step 1 field and obs	User Defines	12.0
DIVLIM	Maximum acceptable divergence	5.E-6	5.E-6
NITER	Max number of passes in divergence minimization	50	50
NSMTH	Number of passes in smoothing (NZ values)	2,4*(NZ-1)	2,4*(NZ-1)
NINTR2	Max number of stations for interpolations (NA values)	99	99
CRITFN	Critical Froude number	1	1
ALPHA	Empirical factor triggering kinematic effects	0.1	0.1
IDIOPT1	Compute temperatures from observations (0 = True)	0	0
ISURFT	Surface station to use for surface temperature (between 1 and NSSTA)	User Defines	1
IDIOPT2	Compute domain-average lapse rates? (0 = True)	0	0
IUPT	Station for lapse rates (between 1 and NUSTA)	User Defines	1
ZUPT	Depth of domain-average lapse rate (m)	200	200
IDIOPT3	Compute internally initial guess winds? (0 = True)	0	0
IUPWND	Upper air station for domain winds (-1 = 1/r**2 interpolation of all stations)	-1	-1
ZUPWND	Bottom and top of layer for 1st guess winds (m)	1,1000	1,1000
IDIOPT4	Read surface winds from SURF.DAT? (0 = True)	0	0
IDIOPT5	Read aloft winds from UPn.DAT? (0 = True)	0	0
CONSTB	Neutral mixing height B constant	1.41	1.41
CONSTE	Convective mixing height E constant	0.15	0.15

Variable	Description	EPA Default	Project Values
CONSTN	Stable mixing height N constant	2400	2400
CONSTW	Over-water mixing height W constant	0.16	0.16
FCORIOL	Absolute value of Carioles parameter	1.E-4	1.E-4
IAVEZI	Spatial averaging of mixing heights? (1 = True)	1	1
MNMDAV	Max averaging radius (number of grid cells)	1	1
HAFANG	Half-angle for looking upwind (degrees)	30	30
ILEVZI	Layer to use in upwind averaging (between 1 and NZ)	1	1
DPTMIN	Minimum capping potential temperature lapse rate	0.001	0.001
DZZI	Depth for computing capping lapse rate (m)	200	200
ZIMIN	Minimum over-land mixing height (m)	50	50
ZIMAX	Maximum over-land mixing height (m)	3000	4500
ZIMINW	Minimum over-water mixing height (m)	50	50
ZIMAXW	Maximum over-water mixing height (m)	3000	4500
IRAD	Form of temperature interpolation (1 = 1/r)	1	1
TRADKM	Radius of temperature interpolation (km)	500	500
NUMTS	Max number of stations in temperature interpolations	5	5
IAVET	Conduct spatial averaging of temperature? (1 = True)	1	0
TGDEFB	Default over-water mixed layer lapse rate (K/m)	-0.0098	-0.0098
TGDEFA	Default over-water capping lapse rate (K/m)	-0.0045	-0.0045
JWAT1	Beginning land use type defining water	999	999
JWAT2	Ending land use type defining water	999	999
NFLAGP	Method for precipitation interpolation (2= 1/r**2)	2	2
SIGMAP	Precip radius for interpolations (km)	100	100
CUTP	Minimum cut off precip rate (mm/hr)	0.01	0.01
SSn	NSSTA input records for surface stations	User Defines	13
Usn	NUSTA input records for upper-air stations	User Defines	10
PSn	NPSTA input records for precipitations stations	User Defines	64

4.4 DISPERSION MODEL INPUT AND OPTIONS

As discussed earlier, the CALPUFF model (EPA-recommended regulatory version 5.8) was used to model emissions of NOx, SO_2, fine particulate matter (PMF) and coarse particulate matter (PMC), elemental carbon (EC) and secondary organic aerosol (SOA) due to the Project. CALPUFF was run using the EPA-recommended default control file settings (Atkinson and Fox 2006) for most parameters. Table 12 displays the CALPUFF options selected for the Ashley modeling. Deviations from EPA-recommended defaults are indicated in bold and discussed in section 4.4.2. Chemical transformations were modeled using the MESOPUFF II chemistry mechanism for conversion of SO_2 to sulfate (SO_4) and NOx to nitric acid (HNO_3) and nitrate (NO_3). Each of these pollutant species were included in the CALPUFF model runs. NOx, HNO_3, and SO_2 were modeled with gaseous deposition, and SO_4, NO_3, PMF ($PM_{2.5}$), and PMC ($PM_{2.5\text{-}10}$), EC and SOA were modeled using particle deposition. Total PM_{10} impacts were determined in the post-processing of modeled impacts, as discussed in Section 4.5.

4.4.1 Background Chemical Species

The CALPUFF chemistry algorithms require hourly measurements of background ozone and a constant estimate of background ammonia concentrations for the conversion of SO_2 and NO_X to sulfates and nitrates, respectively and the equilibrium between gaseous HNO_3 and particulate NO_3.

Background ozone and ammonia data for rural parts of the modeling domain were extremely sparse during the proposed modeling period. Although ozone data is available in regional urban centers, these data are strongly influenced by urban pollution sources and do not accurately represent rural background ozone. In addition, regional ammonia data was only available for a very short period of time (3 weeks) in association with a research study being performed by the Cooperative Institute for Regional Prediction (CIRP).

Because of the lack of observed data, ENVIRON, in consultation with project stakeholders (ENVIRON, 2008) decided to extract surface level ozone and ammonia concentrations from previously performed photochemical modeling. Because of availability and good model performance, 12 km CAMx output that was developed for air quality modeling of the Four Corners region was selected to provide background ozone and ammonia concentration data for the Ashley CALPUFF modeling.

Hourly surface layer concentrations of ozone, ammonia and particulate ammonium were extracted from the 12 km resolution CAMx simulation for the CAMx grid cell that was nearest to the center of the Ashley Modeling domain. For ozone, only data from daylight hours were extracted. The hourly data were then formatted for use in CALPUFF.

In the case of ozone, the modeled hourly values were used directly in calculating the monthly daytime averages. The resultant averages are shown in Figure 9 and range from approximately 40-60 ppb, which is reasonable for rural background ozone (Fiore et al. 2002).

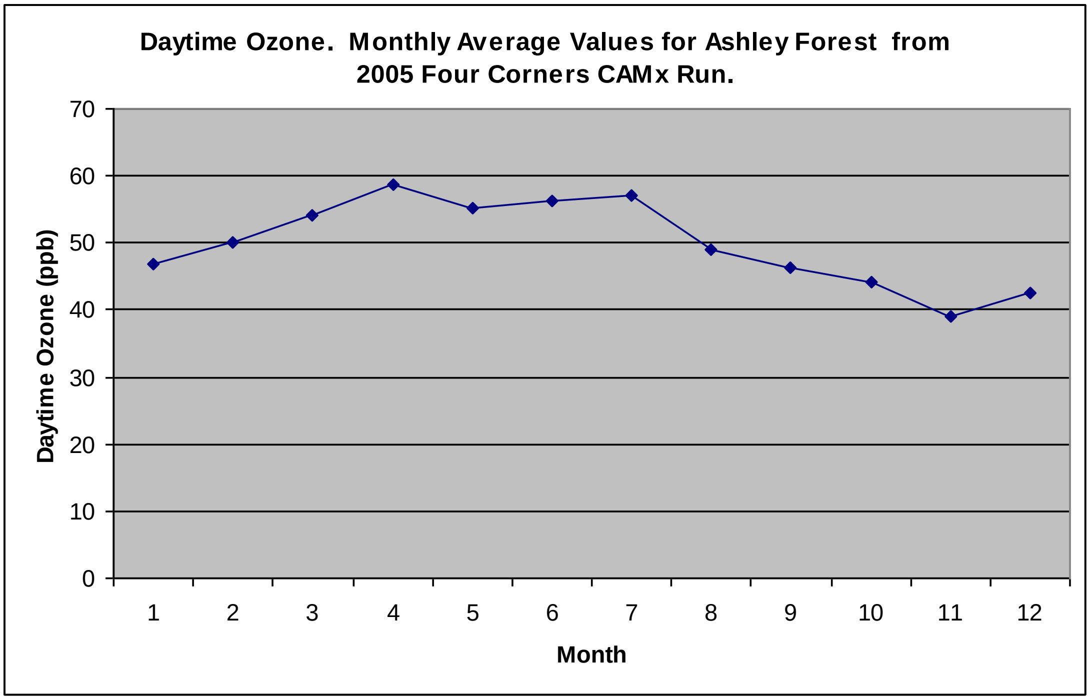


Figure 9**.** Monthly Averaged Daytime Surface Ozone Values for the Ashley Forest Region.

In the case of free gaseous ammonia, the gaseous ammonia and total ammonia (gaseous ammonia plus particulate ammonium) in the CAMx simulation was calculated. This required extracting both gaseous ammonia (NH_3) and particulate ammonium (NH_4). The total potentially available ammonia was then calculated by converting particulate ammonium concentrations (in ug/m^3) to gaseous ammonia concentrations (in ppb) and adding that concentration to the ammonia directly extracted from the CAMx output.

The available background ammonia concentration in the CALPUFF model was used to partition total nitrate between gaseous nitric acid (HNO_3) and particulate ammonium nitrate (NH_4NO_3). This depends on the availability of gaseous ammonia in the atmosphere. Thus, for the CALPUFF modeling, the background gaseous ammonia from the CAMx simulations was used. However, in the future year, reductions in region-wide NOx and SO_2 emissions would reduce background sulfate and nitrate that would free up particulate ammonium to gaseous ammonia. Thus, as a conservative sensitivity analysis the CALPUFF modeling results were processed assuming total ammonia is available as gaseous ammonia.

The resultant monthly averaged gaseous ammonia and total ammonia concentrations are shown in Figure 10 below. Given the vegetation of the modeled region, the monthly average values are consistent with the IWAQM (1998) recommendation of 0.5 ppb for forested lands and 1.0 for arid lands.

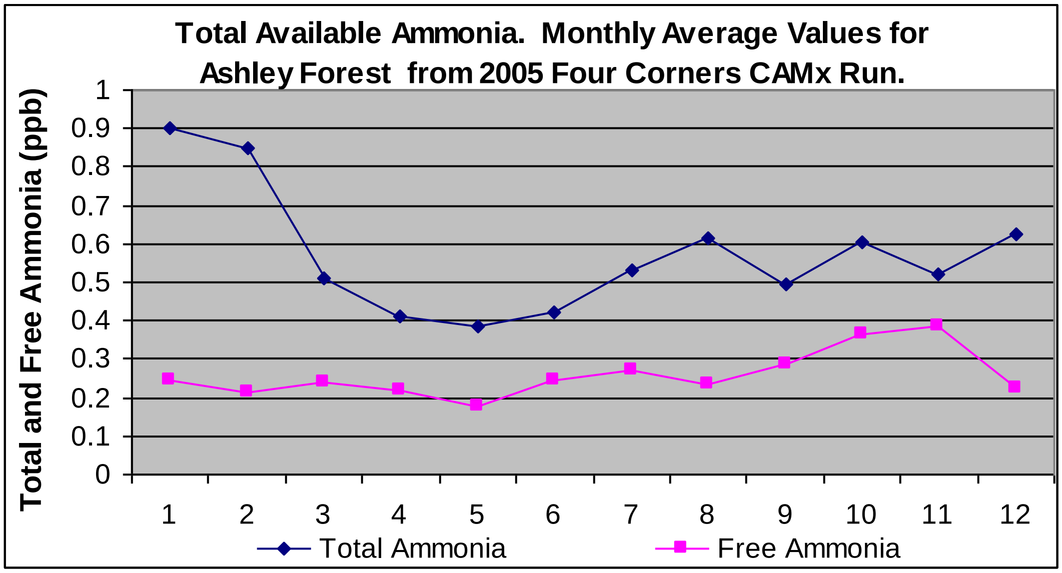


Figure 10**.** Monthly Averaged Total Available Ammonia for the Ashley Forest Region.

4.4.2 Deviations from EPA-Recommended Default Options

As noted by the bold entries in Table 12, several CALPUFF options deviated from EPA-recommended default settings as reported by Atkinson and Fox (2006). First, the EPA-recommended default configuration does not include any PM species, but both fine (PMF) and coarse (PMC) as well as EC and SOA PM species were included in the Ashley modeling. Consequently, we will have more additional emitted (4) and modeled (9) species than appear in the EPA recommendations (3 and 5, respectively). Second, monthly background concentrations of ozone and total available ammonia were used as shown in Figures 9 and 4-10. Note that this background ozone values were only used in the CALPUFF modeling for those hours when hourly ozone observations are missing from all seven ozone monitoring sites in and near the modeling domain.

Table 11. CALPUFF Options Used in the Project's Far-Field Class I and II Area Modeling and Comparison of EPA Regulatory Modeling Default Values (Atkinson and Fox, 2006) (Deviations from EPA Recommended Defaults are Indicated by **Bold Text**.)

Variable	Description	EPA Default	Our Values
METDAT	CALMET input data filename	CALMET.DAT	CALMET.DAT
PUFLST	Filename for general output from CALPUFF	CALPUFF.LST	CALPUFF.LST
CONDAT	Filename for output concentration data	CONC.DAT	CONC.DAT
DFDAT	Filename for output dry deposition fluxes	DFLX.DAT	DFLX.DAT
WFDAT	Filename for output wet deposition fluxes	WFLX.DAT	WFLX.DAT
VISDAT	Filename for output relative humidities (for visibility)	VISB.DAT	VISB.DAT
METRUN	Do we run all periods (1) or a subset (0)?	0	0
IBYR	Beginning year	User Defined	User Defined
IBMO	Beginning month	User Defined	User Defined
IBDY	Beginning day	User Defined	User Defined
IBHR	Beginning hour	User Defined	User Defined
IRLG	Length of runs (hours)	User Defined	User Defined
NSPEC	Number of species modeled (for MESOPUFF II chemistry)	**5**	**7**
NSE	Number of species emitted	**3**	**4**
MRESTART	Restart options (0 = no restart), allows splitting runs into smaller segments	**0**	**2 or 3**
METFM	Format of input meteorology (1 = CALMET)	1	1
AVET	Averaging time lateral dispersion parameters (minutes)	60	60
MGAUSS	Near-field vertical distribution (1 = Gaussian)	1	1
MCTADJ	Terrain adjustments to plume path (3 = Plume path)	3	3
MCTSG	Do we have subgrid hills? (0 = No), allows CTDM-like treatment for subgrid scale hills	0	0
MSLUG	Near-field puff treatment (0 = No slugs)	0	0
MTRANS	Model transitional plume rise? (1 = Yes)	1	1
MTIP	Treat stack tip downwash? (1 = Yes)	1	1
MSHEAR	Treat vertical wind shear? (0 = No)	0	0
MSPLIT	Allow puffs to split? (0 = No)	0	0

Variable	Description	EPA Default	Our Values
MCHEM	MESOPUFF-II Chemistry? (1 = Yes)	1	1
MWET	Model wet deposition? (1 = Yes)	1	1
MDRY	Model dry deposition? (1 = Yes)	1	1
MDISP	Method for dispersion coefficients (3 = PG & MP)	3	3
MTURBVW	Turbulence characterization? (Only if MDISP = 1 or 5)	3	3
MDISP2	Backup coefficients (Only if MDISP = 1 or 5)	3	3
MROUGH	Adjust PG for surface roughness? (0 = No)	0	0
MPARTL	Model partial plume penetration? (0 = No)	1	1
MTINV	Elevated inversion strength (0 = compute from data)	0	0
MPDF	Use PDF for convective dispersion? (0 = No)	0	0
MSGTIBL	Use TIBL module? (0 = No) allows treatment of subgrid scale coastal areas	0	0
MREG	Regulatory default checks? (1 = Yes)	1	1
CSPECn	Names of species modeled (for MESOPUFF II, must be SO_2, SO_4, NOx, HNO_3, NO_3)	User Defined	SO_2, SO_4, NOx, HNO_3, NO_3, PMF, PMC, EC, SOA
Specie Names	Manner species will be modeled	User Defined	SO_2, SO_4, NO_X, NO_3, HNO_3, PMF, PMC, EC, SOA
Specie Groups	Grouping of species, if any.	User Defined	
NX	Number of east-west grids of input meteorology	User Defined	127
NY	Number of north-south grids of input meteorology	User Defined	152
NZ	Number of vertical layers of input meteorology	User Defined	11
DGRIDKM	Meteorology grid spacing (km)	User Defined	4
ZFACE	Vertical cell face heights of input meteorology	User Defined	0., 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 4500
XORIGKM	Southwest corner (east-west) of input meteorology	User Defined	-1180.0

Variable	Description	EPA Default	Our Values
YORIGIM	Southwest corner (north-south) of input meteorology	User Defined	-64.
IUTMZN	UTM zone	User Defined	NA
XBTZ	Base time zone of input meteorology	User Defined	7
IBCOMP	Southwest of Xindex of computational domain	User Defined	1
JBCOMP	Southwest of Y-index of computational domain	User Defined	34
IECOMP	Northeast of Xindex of computational domain	User Defined	127
JECOMP	Northeast of Y- index of computational domain	User Defined	152
LSAMP	Use gridded receptors (T -= Yes)	F	F
IBSAMP	Southwest of Xindex of receptor grid	User Defined	NA
JBSAMP	Southwest of Y-index of receptor grid	User Defined	NA
IESAMP	Northeast of Xindex of receptor grid	User Defined	NA
JESAMP	Northeast of Y-index of receptor grid	User Defined	NA
MESHDN	Gridded receptor spacing = DGRIDKM/MESHDN	1	NA
ICON	Output concentrations? (1 = Yes)	1	1
IDRY	Output dry deposition flux? (1 = Yes)	1	1
IWET	Output wet deposition flux? (1 = Yes)	1	1
IVIS	Output RH for visibility calculations (1 = Yes)	1	1
LCOMPRS	Use compression option in output? (T = Yes)	T	T
ICPRT	Print concentrations? (0 = No)	0	0
IDPRT	Print dry deposition fluxes (0 = No)	0	0
IWPRT	Print wet deposition fluxes (0 = No)	0	0
ICFRQ	Concentration print interval (1 = hourly)	1	1
IDFRQ	Dry deposition flux print interval (1 = hourly)	1	1
IWFRQ	Wet deposition flux print interval (1 = hourly)	1	1
IPRTU	Print output units (1 = g/m**3; g/m**2/s)	1	1
IMESG	Status messages to screen? (1 = Yes)	1	1
Output Species	Where to output various species	User Defined	Default
LDEBUG	Turn on debug tracking? (F = No)	F	F

Variable	Description	EPA Default	Our Values
Dry Gas Dep	Chemical parameters of gaseous deposition species	User Defined	Default
Dry Part. Dep	Chemical parameters of particulate deposition species	User Defined	Default
RCUTR	Reference cuticle resistance (s/cm)	30.	30.
RGR	Reference ground resistance (s/cm)	10.	10.
REACTR	Reference reactivity	8	8
NINT	Number of particle-size intervals	9	9
IVEG	Vegetative state (1 = active and unstressed)	1	1
Wet Dep	Wet deposition parameters	User Defined	Default
MOZ	Ozone background? (1 = read from ozone.dat)	1	1
BCKO3	Ozone default (ppb) (Use only for missing data)	***80***	**See Figure 9**
BCKNH3	Ammonia background (ppb)	**10**	**See Figure 10**
RNITE1	Nighttime SO_2 loss rate (%/hr)	0.2	0.2
RNITE2	Nighttime NOx loss rate (%/hr)	2	2
RNITE3	Nighttime HNO_3 loss rate (%/hr)	2	2
SYTDEP	Horizontal size (m) to switch to time dependence	550.	550.
MHFTSZ	Use Heffter for vertical dispersion? (0 = No)	0	0
JSUP	PG Stability class above mixed layer	5	5
CONK1	Stable dispersion constant (Eq. 2.7-3)	0.01	0.01
CONK2	Neutral dispersion constant (Eq. 2.7-4)	0.1	0.1
TBD	Transition for downwash algorithms (0.5 = ISC)	0.5	0.5
IURB1	Beginning urban land use type	10	10
IURB2	Ending urban land use type	19	19

4.4.3 Model Receptors

The National Park Service (NPS) has posted receptors for Class I areas on their website that are recommended for use in CALPUFF model applications at which the concentration, deposition, and AQRV impacts are calculated. The NPS Class I area receptors were downloaded from their website and converted to the LCC coordinate system. The downloaded receptors were used in the Project's CALPUFF modeling. Receptors were also specified across the far-field Class II areas using a similar density as used in the NPS Class I area receptors. In addition, single discrete receptors were defined for each acid-sensitive lake in the domain. Figure 8 displays the locations of the Class I area receptors used in the CALPUFF modeling.

4.4.4 Emissions Processing

CALPUFF source parameters were determined for all Project and regional source emissions of NOx, SO_2, PMF, and PMC. Project sources were input to CALPUFF using 4 km^2 area sources at 4 km spacing placed throughout the Project area to idealize project well operation and construction emissions. For each of the three modeling years, the required number of wells was randomly distributed throughout the Project area. Once the wells had been located in the Project area, the wells were assigned to a particular grid cell of the CALPUFF modeling domain, and the emissions for each grid cell were taken to be the sum of the emissions from all wells within that 4 km grid cell. Figure 11 displays the relationship between the well locations for the Proposed Action and the Class I area receptors used in the CALPUFF modeling.

Point sources were used to represent central compressor stations. Compressor station emissions are provided in Appendix A. Stack parameters for the central compressor stations were based on those used in the Jonah Infill Project EIS Modeling and are shown in Table 13.

Table 12**.** Central Compressor Station Stack Parameters.

Stack Height	Stack Height	Temperature	Exit Velocity
0.515 m	10.97 m	730 K	40.48 m/s

The exact location of the proposed compressor stations is not yet known; therefore, compressor stations were sited within the Project area based on the randomly chosen well locations. Wells were split into four equal groups and a compressor station was placed in the centroid of each group. Once a compressor station had been located within a 4 km^2 grid cell, the emissions from that compressor station were added to those of the project wells within that grid cell. Figure 12 shows the randomly chosen well sites and the hypothetical locations of the four central compressor stations.

Non-project regional emissions were input to CALPUFF using point sources to represent state-permitted and RFFA sources. Both state-permitted sources and RFFA emissions were supplied for Wyoming; for Utah and Colorado; only state-permitted sources were supplied. CALPUFF requires stack parameters (stack diameter and height, exit velocity, and exit temperature) for all point sources. Where stack parameters were not supplied in the state inventories, default stack parameters based on the Atlantic Rim Technical Support Document, Appendix C, Table C7 were used. These parameters are shown in Table 14.

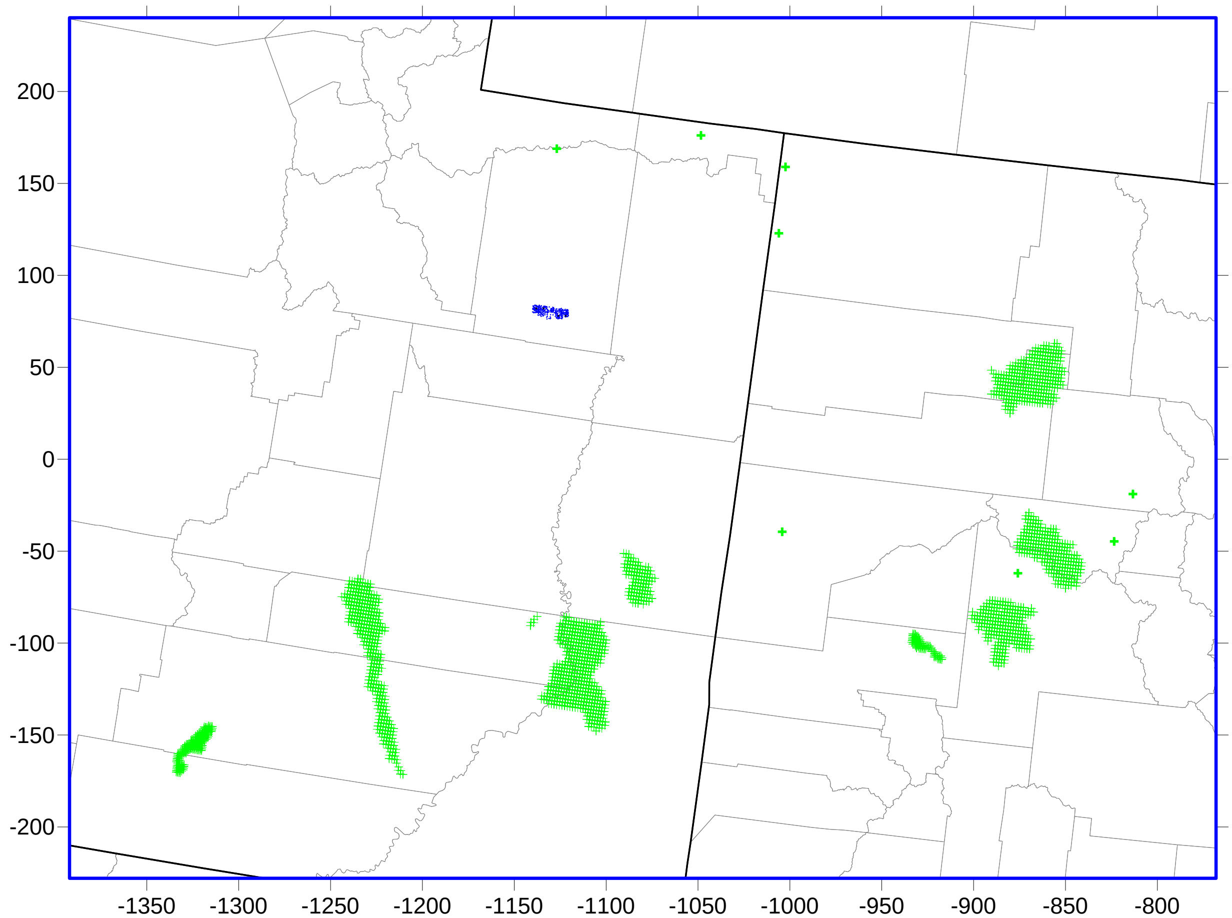
Table 13. Default Stack Parameters for Cumulative Sources with Missing Stack Parameter Data.

Stack Height	Stack Height	Temperature	Exit Velocity
0.51 m	9.82 m	633.80 K	30.08 m/s

For Wyoming, state permitted and RFFA sources that did not have specific coordinates (i.e. no latitude/longitude or UTM easting/northing coordinate pair was present for that source), the source was sited at the centroid of its section if township, range, and section data were available. For cases where no coordinates were given and no township, range, and section data were present, the source was located at the county centroid if county information was given.

The cumulative emission inventory for the three states contains more than 2,000 state-permitted and RFFA sources. A three-year simulation with such a large number of sources places prohibitive computational demands on CALPUFF given the number of receptors, the domain size, and the time constraints of the project. Therefore, we reduced the number of sources input (but keeping total emissions) in CALPUFF that represent the permitted and RFFA sources in Wyoming by treating emissions from all permitted and RFFA sources with the classification "production site" in the same manner as those of the Project well sites. The Wyoming permitted and RFFA production site sources were gridded as 4 km by 4 km area sources, and emissions sources from the remainder of the source classifications were treated as point sources.

RFD emissions were modeled using area sources developed as a “best fit” to the Project Area. The area source definitions for the RFD emissions are shown in Figure 13. County-wide well sites were also modeled as area sources, with the counties idealized as polygons suitable for input to CALPUFF. The idealization of the county areas is shown in Figure 14.



Ashley NF South Unit Modeling Domain
LCP center at 40N, 97W, true latitudes at 33N, 45N
4km domain: 156x117 (-1392,-228) to (-768,240)

Figure 11**.** CALMET and CALPUFF Modeling Domains. Randomly located hypothetical Ashley Project Well Locations are shown as Blue Crosses and Class I Area Receptors are shown as Green Crosses.

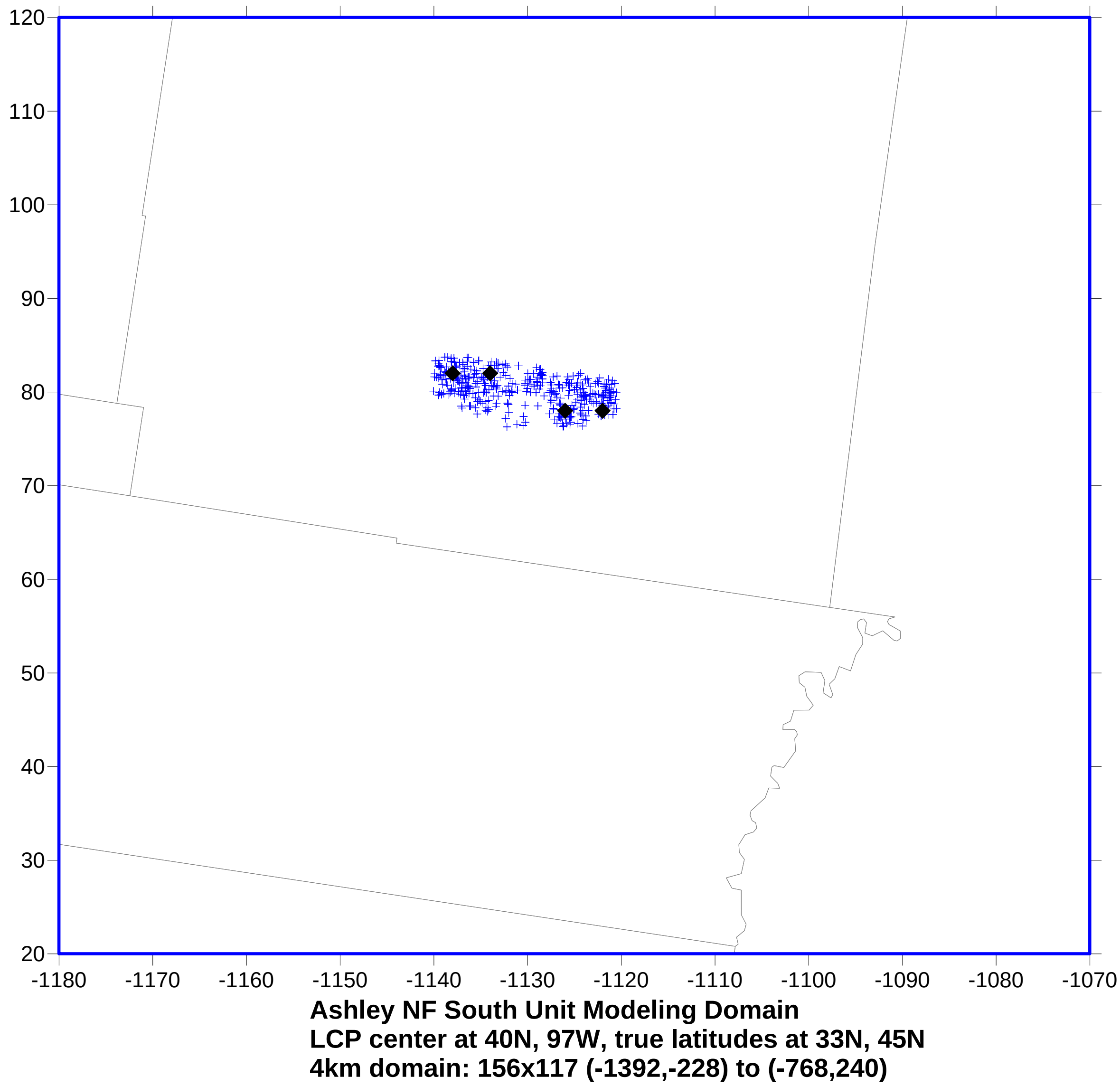


Figure 12**.** Map of Ashley Scenario Showing Location of Random Hypothetical Well Sites (Blue Crosses), Central Compressor Stations (Black Diamonds).

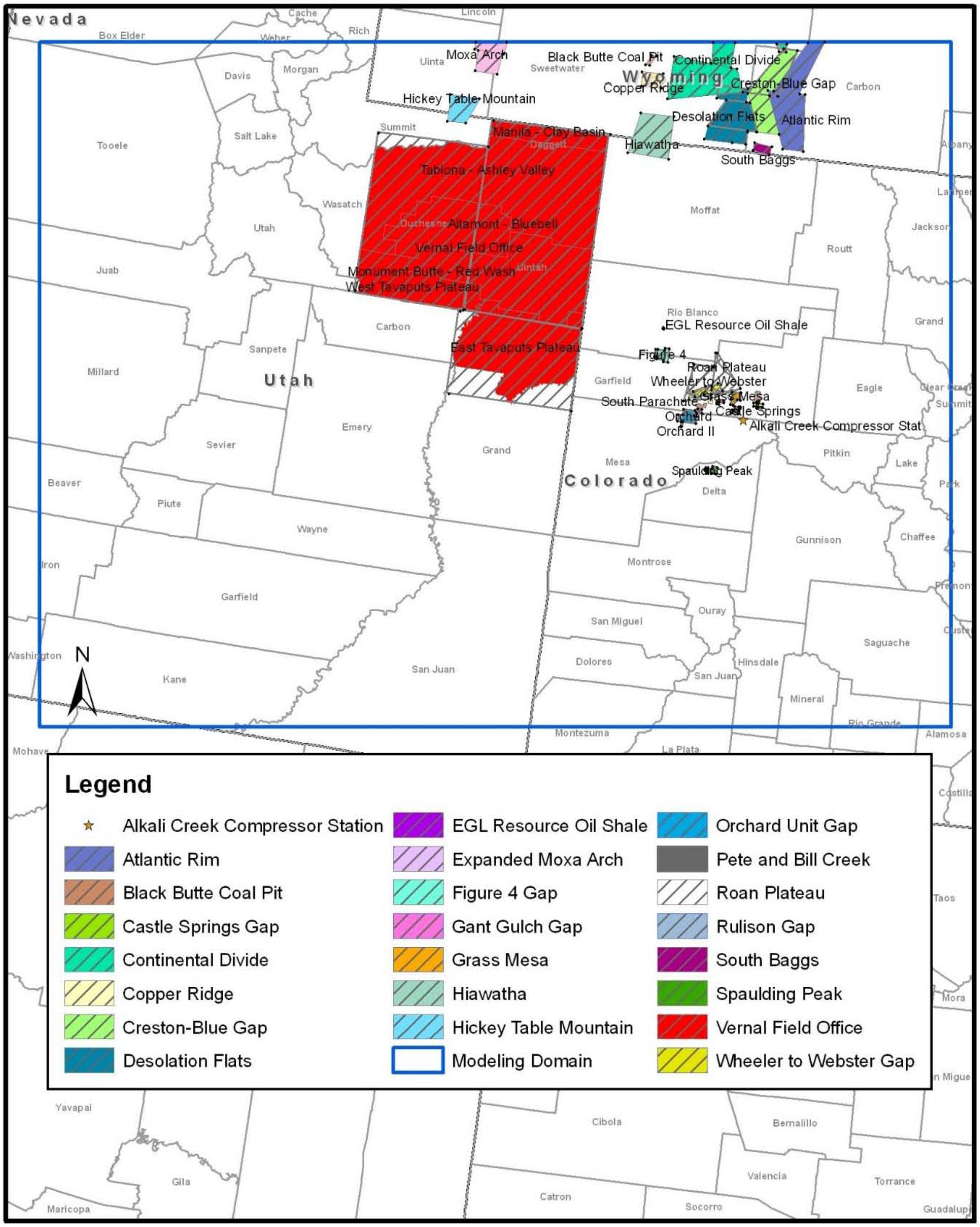


Figure 13. Far-field Modeling Area Source Idealization of NEPA RFD Project Areas. The spatial distribution of sources in the Vernal Plateau area is not yet determined, so the entire Vernal Plateau was used as the source area for Vernal Field Office sources (sources VF0-1, VFO-2, and VFO-3). Source RP-1 is the Roan Plateau area. All other sources are listed in the legend.

Figure 14. Far-field Modeling Area Source Idealization of County Well Site Emissions.

4.5 POST-PROCESSING PROCEDURES AND BACKGROUND AIR QUALITY DATA

The CALPUFF concentration and deposition outputs were post-processed to analyze the following (details on the CALPUFF post-processing procedures are contained in Sections 4.6 and 4.7):

- Compared against the PSD Class I and II increments at the Class I and II receptor areas, respectively.
- Added to background values provided by the State of Utah DEQ and the CDPHE/APCD and compared to the NAAQS/UAAQS/CAAQS for criteria pollutants.
- Analyzed to determine total nitrogen and sulfur deposition impacts and were compared to the NFS significant deposition analysis thresholds (DATs).
- Analyzed for Acid Neutralizing Capacity (ANC) at sensitive lakes in the region.
- Analyzed for visibility impacts and compared against the 0.5 and 1.0 change in deciview thresholds.

4.5.1 Criteria Pollutants

Under federal and state PSD regulations, increases in ambient air concentrations in Class I areas are limited by PSD Class I and II Increments. Emissions associated with a particular development may increase ambient concentrations above baseline levels only within those specific increments developed for SO_2, PM_{10}, and NO_2. PSD Class I and PSD Class II increments are set forth in federal and state PSD regulations and are shown in Table 15.

Table 15 Ambient Air Quality Standards and Class 1 and II PSD Increments (µg/m^3).

Pollutant/ Averaging Time	NAAQS	CAAQS	UAAQS	PSD Class I Increment[1]	PSD Class II Increment[1]
CO					
1-hour[2]	40,000	40,000	40,000	--[3]	--[3]
8-hour[2]	10,000	10,000	10,000	--	--
NO_2					
1-hour[8]	188				
Annual[4]	100	100	100	2.5	25
O_3					
8-hour[6]	147	147	147	--	--
PM_{10}					
24-hour[2]	150	150	150	8	30
Annual[4]	--[5]	50	50	4	17
$PM_{2.5}$					
24-hour[7]	35	35	35	--[3]	--[3]
Annual[4]	15	15	15	--	--
SO_2					
1-hour[9]	196				
3-hour[2]	1,300	700	1,300	25	512
24-hour[2]	365	365	365	5	91
Annual[4]	80	60	80	2	20

µg/m^3 = micrograms per cubic meter
PSD = Prevention of Significant Deterioration
[1] The PSD demonstrations serve information purposes only and do not constitute a regulatory PSD increment consumption analysis.
[2] No more than one exceedence per year.
[3] No PSD increments have been established for this pollutant.
[4] Annual arithmetic mean.
[5] The NAAQS for this averaging time for this pollutant has been revoked by EPA.
[6] An area is in compliance with the standard if the fourth-highest daily maximum 8-hour ozone concentrations in a year, averaged over 3 years, is less than or equal to the level of the standard.
[7] An area is in compliance with the standard if the 98th percentile of 24-hour PM2.5 concentrations in a year, averaged over 3 years, is less than or equal to the level of the standard.

[8] An area is in compliance with the standard if the 98th percentile of daily maximum 1-hour NO_2 concentrations in a year, averaged over 3 years, is less than or equal to the level of the standard.
[9] An area is in compliance with the standard if the 99th percentile of daily maximum 1-hour SO_2 concentrations in a year, averaged over 3 years, is less than or equal to the level of the standard.
Source: (D. Prey, Utah Department of Environmental Quality Division of Air Quality, personal communication, 2008).

CALPUFF modeling results predicted within Federal PSD Class I areas were compared to PSD Class I Increments. Modeled fields predicted at sensitive receptor areas designated as PSD Class II areas were compared to PSD Class II Increments. These demonstrations are for informational purposes only and are not regulatory PSD Increment consumption analyses, which are completed as necessary during the permitting process by the relevant state.

CALPUFF modeled concentrations predicted in PSD Class I and sensitive Class II areas were added to applicable background concentrations and then compared to ambient air quality standards shown in Table 15 that includes the National, Utah and Colorado Ambient Air Quality Standards (i.e., NAAQS, UAAQS and CAAQS). Background concentrations are discussed in the next section.

4.5.2 Background Data for Criteria Pollutants

Ambient air concentration data collected at monitoring sites in the region provide a measure of background conditions in existence during the most recent available time period. The Utah Department of Environmental Quality (UDEQ) and the Air Pollution Control Division (APCD) of the Colorado Department of Public Health and Environment (CDPHE) recommended background concentrations to be used for the region. The UDEQ provided background concentrations for SO_2, NO_2, PM_{10} and CO for eight counties in Utah. The CDPHE/APCCD provided background concentrations for the same four species plus $PM_{2.5}$ and ozone that are representative of rural areas of the Piceance Basin region in Colorado. The background values provided by UDEQ and CDPHE/APCD are shown in Table 16.

Table 14. Far-Field Analysis Background Ambient Air Quality Concentrations.[1]

Pollutant	Averaging Period	Measured Background Concentration (μg/m^3)
Carbon County, Utah		
Carbon monoxide (CO)	1-hour	1
	8-hour	1
Nitrogen dioxide (NO2)	1hour	N/A
	Annual	17
Ozone (O3)3	1-hour	NA
	8-hour	NA
PM10	24-hour	30
	Annual	13
PM2.5	24-hour	NA
	Annual	NA

Sulfur dioxide (SO2)	1-hour	20
	3-hour	20
	24-hour	10
	Annual	5
Duchesne County, Utah		
Carbon monoxide (CO)	1-hour	1
	8-hour	1
Nitrogen dioxide (NO2)	1-hour	N/A
	Annual	10
Ozone (O3)3	1-hour	NA
	8-hour	NA

Pollutant	Averaging Period	Measured Background Concentration ($\mu g/m^3$)
PM10	24-hour	28
	Annual	10
PM2.5	24-hour	27.6
	Annual	9.3
Sulfur dioxide (SO2)	1-hour	20
	3-hour	20
	24-hour	10
	Annual	5
Pollutant	Averaging Period	Measured Background Concentration (μg/m3)
Emery County, Utah		
Carbon monoxide (CO)	1-hour	1
	8-hour	1
Nitrogen dioxide (NO2)	1-hour	N/A
	Annual	17
Ozone (O3)3	1-hour	NA
	8-hour	NA
PM10	24-hour	30
	Annual	13
PM2.5	24-hour	NA
	Annual	NA
Sulfur dioxide (SO2)	1-hour	20
	3-hour	20
	24-hour	10
	Annual	5
Pollutant	Averaging Period	Measured Background Concentration (μg/m3)
Grand County, Utah		
Carbon monoxide (CO)	1-hour	1
	8-hour	1
Nitrogen dioxide (NO2)	1-hour	N/A
	Annual	10
Ozone (O3)3	1-hour	NA
	8-hour	NA
PM10	24-hour	67
	Annual	21.8
PM2.5	24-hour	NA
	Annual	NA

Sulfur dioxide (SO2)	1-hour	20
	3-hour	20
	24-hour	10
	Annual	5

[1]Personal communication Utah DAQ, (2012)
$\mu g/m^3$ = micrograms per cubic meter

4.5.3 Visibility

Change in atmospheric light extinction relative to background conditions is used to measure regional haze. Analysis thresholds for atmospheric light extinction are set forth in FLAG (2000), with the results reported as percent change in light extinction and change in deciview over background. The FLAG thresholds are defined as 5% and 10% changes in light extinction over a reference background visibility, which is essentially numerically equivalent to a 0.5 and 1.0 change in deciview (dv), for project sources alone and cumulative source impacts, respectively. FLAG (2000) also identifies a goal that any specific project combined with cumulative new source growth will have no days of visibility impairment at or above 1.0 dv in any Class I area. These thresholds and the FLAG guidelines were developed for New Source Review (NSR) applications where an AQRV analysis is required as part of a PSD permit application. The BLM considers a 1.0 dv change to be a significant adverse impact; however, there are no applicable local, state, tribal, or Federal regulatory visibility standards.

Visibility impact assessments following FLAG guidance are typically based on the maximum predicted daily (24-hour) average visibility impacts across all receptors in a Class I or sensitive Class II area that is evaluated on an annual basis. The maximum number of days above threshold values and the maximum predicted impacts are typically reported. Visibility impact assessments following EPA's regional haze rule guidance (EPA, 2005) for Best Available Retrofit Technology (BART) modeled uses the annual 98^{th} percentile maximum predicted daily values (8^{th} highest daily value in a year) for assessing visibility impacts.

Changes in light extinction from CALPUFF incremental model concentration estimates due to emissions from the Project were calculated for each day at all receptors covering the Class I and sensitive Class II areas. Comparisons of the contribution of the Project to changes in light extinction were compared to the 1.0 and 0.5 dv change thresholds.

CALPUFF does not directly output visibility impairment, but instead outputs fine particle matter species concentrations that need to be converted to visibility metrics. CALPUFF will provide sulfate (SO_4), nitrate (NO_3), other fine particulate (PMF) and coarse particulate (PMC) PM species concentration estimates. The FLAG procedures for evaluating visibility impacts at Class I areas uses the original IMPROVE reconstructed mass extinction equation to convert PM species in μg/m^3 to light extinction (b_{ext}) in Mm^{-1} as follows:

$$\mathbf{b_{ext} = b_{SO4} + b_{NO3} + + b_{EC} + b_{OC} + b_{PMF} + b_{PMC}}$$

$$\mathbf{b_{SO4} = 3\,[(NH_4)_2SO_4]f(RH)}$$
$$\mathbf{b_{NO3} = 3\,[NH_4NO_3]f(RH)}$$
$$\mathbf{b_{EC} = 10\,[EC]}$$
$$\mathbf{b_{OC} = 4[OC]}$$
$$\mathbf{b_{PMF} = 1\,[PMF]}$$
$$\mathbf{b_{PMC} = 0.6\,[PMC]}$$

Here f(RH) are relative humidity adjustment factors and for refined CALPUFF modeling calculations FLAG recommends using day-specific (MVISBK=2) hourly f(RH) values that are based on hourly RH measurements at a nearby meteorological monitoring site. However, results are also frequently presented using monthly average (MVISBK=6) f(RH) values. The visibility evaluation metric is the change in extinction (Δb_{ext}) expressed as percent or change in deciview (Δdv) over a visibility background ($b_{background}$) as follows:

$$\Delta b_{ext} = 100 \text{ x } (b_{ext} / b_{background})$$

$$\Delta dv = 10 \ln[\ (b_{ext}+b_{background})/b_{background}]$$

There are several methods that have been used to assess visibility impacts. These methods differ in their selection of background visibility data, relative humidity data, and the equation used to calculate light extinction (i.e., original or revised IMPROVE equation). The two methods used to estimate visibility impairment are summarized in Table 17.

Table 15. Summary of Visibility Impact Assessment Methods to be Used in the Ashley Modeling Study.

Method	Background data	f(RH)	Revised IMPROVE Equation?
FLAG (Method 6)	FLAG	Monthly	No
FLAG (Method 2)	FLAG	Hourly	No

Both of the visibility impact assessment procedures use the FLAG default background, and both methods use the original IMPROVE equation (Malm et al., 2000). The methods are used to calculate the change in light extinction over background conditions and use either monthly average (FLAG Method 6) or hourly (FLAG Method 2) relative humidity adjustment factors [f(RH)]. For the FLAG Method 6, monthly relative humidity factors provided in the *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003b) were used. In the FLAG Method 2, CALPOST uses the hourly RH data from the closest monitoring site to the Class I area. Both methods use a 98% maximum RH value. Many of the recent applications of the FLAG Method 2 approach have used a 95% maximum RH value that will also be used in the Ashley modeling study.

FLAG (2000) has provided natural background data for Federal Class I areas only, so data from the nearest Federal Class I area were used for the sensitive Class II receptor areas. The natural background visibility data, in units of inverse megameters (Mm^{-1}), that were used with the two FLAG method visibility analyses for each area analyzed are given in the FLAG (2000) report. An example of the FLAG natural background for the Mount Zirkel Wilderness Area in northern Colorado is shown in Table 18.

Table 16**.** Example FLAG (2000) Dry Background Extinction Values Below is an example of variables for Mount Zirkel Wilderness area.

Site	Season	Hygroscopic (Mm^{-1})	Non-hygroscopic (Mm^{-1})
Mount Zirkel Wilderness Area	Winter	0.6	4.5
	Spring	0.6	4.5
	Summer	0.6	4.5
	Fall	0.6	4.5

Additional values can be found at http://www2.nature.nps.gov/air/Permits/flag/index.cfm for Class 1 areas within the modeling domain. (Flag, 2000 pp 46-67)

4.5.4 Deposition

Maximum annual predicted sulfur (S) and nitrogen (N) deposition impacts across all receptors in a far-field Class I or sensitive Class II receptor area were estimated for each present and future year scenario run with CALPUFF. Predicted S and N deposition due to the Project were compared to the NPS Deposition Analysis Thresholds (DATs) that are defined as 0.05 kg/ha-yr for the western U.S.

4.5.5 Lake Chemistry

The CALPUFF-predicted annual deposition fluxes of S and N at sensitive lake receptors were used to estimate the change in ANC. The change in ANC was calculated following the January 2000, USFS Rocky Mountain Region's *Screening Methodology for Calculating ANC Change to High Elevation Lakes, User's Guide* (USFS, 2000). The predicted changes in ANC were compared with the USFS Level of Acceptable Change (LAC) thresholds of 10% for lakes with ANC values greater than 25 μeq/l. A 1 μeq/l threshold is recommended for lakes with background ANC values of 25 μeq/l and less but there are no such extremely sensitive lakes in the Ashley modeling domain. Lake impacts were assessed with consideration of the limited data points available for several analyzed lakes.

The most recent lake chemistry background ANC data have been obtained from the Forest Service for each sensitive lake to be analyzed. The 10th percentile lowest ANC values were calculated for each lake following procedures recommended by the USFS. The ANC values proposed for use in this analysis, and the number of samples used in the calculation of the 10^{th} percentile lowest ANC values, are shown in Table 19. Of the lakes listed in Table 19, none is considered by the USFS to be extremely sensitive to atmospheric deposition since none of the background ANC values is less than 25 microequivalents per liter (μeq/l).

Table 17. Background ANC Values for Acid Sensitive Lakes.

Wilderness Area	Lake	Latitude (Degrees)	Longitude (Degrees)	10th Percentile Lowest ANC Value (μeq/l)[2]	Number of Samples	Monitoring Period
Ashley	Bluebell Lake	40.6958	-110.486	56.12	2	1985-2002
Ashley	Dean Lake	40.6786	-110.761	44.71	7	1985-2007
UWC	Fish Lake	40.8366	-110.069	96.85	6	2001-2007
Ashley	No Name Lake	40.6708	-110.275	54.94	2	1985-2007
Ashley	Walkup Lake	40.8113	-110.039	54.68	5	2002-2007

[2] 10^{th} Percentile Lowest ANC Values reported. μeq/l = microequivalents per liter

CLASS I AREA FAR-FIELD AIR QUALITY AND AQRV IMPACT ASSESSMENT

CALPUFF modeling was performed to compute direct Project impacts for the Ashley Project and to estimate cumulative impacts from the Project and other regional emission sources. The modeled year, as described in Sections 1.2 and 4.2, represents a maximum emission scenario of the last year of field development at nearly full-field production. Regional emission inventories for existing state-permitted Reasonably Foreseeable Future Action (RFFA) and Reasonably Foreseeable Development (RFD) sources, as described in Section 2 and Appendix B, were modeled in combination with the Project scenario to estimate cumulative impacts. Since the RFD sources are speculative, we also analyzed a scenario that consists of the Project plus all cumulative emissions less the RFD sources.

For each far-field sensitive area, CALPUFF-modeled concentration impacts were post-processed with POSTUTIL and CALPOST to derive: (1) concentrations for comparison to ambient standards (WAAQS, CAAQS, UAAQS, and NAAQS) and PSD Class I and II Increments; (2) deposition rates for comparison to S and N deposition thresholds and to calculate changes to acid neutralizing capacity (ANC) at sensitive lakes; and (3) light extinction changes for comparison to visibility impact thresholds.

4.5.6 Far-Field Concentration Impacts

The CALPOST and POSTUTIL post-processors were used to summarize potential concentration impacts of NO_2, SO_2, PMF, and PMC at PSD Class I and sensitive PSD Class II areas. Predicted impacts are compared to applicable ambient air quality standards, PSD Class I and Class II increments, and significance levels. Table 31 lists the ambient standards and PSD Class I and II increments to which the potential concentration impacts due to the Project alone and the Project plus cumulative emissions were compared.

PM_{10} concentrations were computed by adding predicted CALPUFF concentrations of PMF, PMC, SO_4, and NO_3, whereas $PM_{2.5}$ concentrations were calculated as the sum of modeled PMF, SO_4, and NO_3 concentrations.

4.5.6.1 Class I Area Far-Field Concentration Results

The maximum potential predicted concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$ at any receptor within each of the PSD Class I areas for the Project are shown in Table 20. The highest estimated concentration impacts at any Class I area and the Project occur at the Arches National Park Class I area. All of the impacts are less than 1% of the PSD Class I area increments. The largest potential impact is for 24-hour PM_{10} where CALPUFF is estimating values ~0.8% of the PSD Class I area increment at Arches National Park in Utah. The far-field results demonstrate that the maximum potential air quality impacts for the Project would not exceed any PSD Class I increment at any Class I area.

Table 21 displays the maximum potential PSD pollutant concentrations at Class I areas due to the Project plus the Cumulative Emissions inventory (including RFD) and compares them to the PSD Class I increments. The highest potential estimated impacts due to the Cumulative Emissions plus the Project occur for the Flat Tops WA, Maroon Bells-Snowmass WA, Canyonlands NP, Capitol Reef NP and Arches NP; impacts are:

- Less than 2% of the PSD Class I increments for annual, 24-hour and 3-hour SO2 concentrations;
- Less than 2% and 5% of the PSD Class I area increments for annual and 24-hour PM10, respectively; and
- Less than 9% of the PSD Class I area increment for annual NO2.

Table 21 shows that the estimated potential air quality impacts due the Project plus the cumulative emissions would not exceed any PSD Class I area increment at any Class I area.

Table 4-22 displays the maximum estimated potential PSD pollutant concentrations at Class I areas due to the Project plus the cumulative emissions inventory without RFD sources. The PSD Class I increments are also shown in Table 4-12. The highest estimated impacts due to the cumulative emissions without RFD sources plus the Project occur at the Flat Tops, Arches, Capitol Reef and Canyonlands Class I Areas. Impacts are:

- Less than 2% of the PSD Class I increments for annual, 24-hour and 3-hour SO2 concentrations;
- Less than 1% and 3% of the PSD Class I area increments for annual and 24-hour PM10, respectively; and
- Less than 8% of the PSD Class I area increment for annual NO2.

Table 4-12 shows that the estimated potential air quality impacts due to the Project plus the cumulative emissions without RFD sources would not exceed any PSD Class I area increment at any Class I area As expected, the impacts are slightly less than for the case with the RFD sources included in the cumulative emission inventory (Table 4-21).

Table 18**.** CALPUFF Estimated PSD Pollutant Concentrations Impacts at Class I Areas for the Proposed Project. PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

Species and Averaging Time	**PSD Class I Area Increment (µg/m3)**	**Concentration Estimates (µg/m^3)**							
		Flat Tops	**Maroon Bells**	**West Elk**	**Black Canyon**	**Arches**	**Capitol Reef**	**Canyon-lands**	**Bryce Canyon**
2002									
SO_2 3-Hour*	25.00	0.000071	0.000063	0.000050	0.000090	0.000318	0.000103	0.000166	0.000054
SO_2 24-Hour*	5.00	0.000023	0.000019	0.000020	0.000032	0.000144	0.000036	0.000063	0.000012
SO_2 Annual	2.00	0.000003	0.000002	0.000002	0.000002	0.000009	0.000002	0.000005	0.000000
PM_{25} 24-Hour*		0.006431	0.005538	0.005587	0.009457	0.030577	0.009246	0.020226	0.003174
PM_{25} Annual		0.000794	0.000510	0.000432	0.000534	0.001830	0.000534	0.001146	0.000148
PM_{10} 24-Hour*	4.00	0.006459	0.005589	0.005607	0.009508	0.031055	0.009622	0.020386	0.003670
PM_{10} Annual	8.00	0.000839	0.000534	0.000447	0.000553	0.001913	0.000550	0.001194	0.000154
NO_2 Annual	2.50	0.000090	0.000057	0.000040	0.000096	0.000970	0.000074	0.000423	0.000003
2005									
SO_2 3-Hour*	25.00	0.000116	0.000066	0.000074	0.000071	0.000251	0.000133	0.000159	0.000047
SO_2 24-Hour*	5.00	0.000035	0.000025	0.000019	0.000023	0.000079	0.000044	0.000064	0.000012
SO_2 Annual	2.00	0.000004	0.000002	0.000002	0.000002	0.000007	0.000002	0.000005	0.000001
PM_{25} 24-Hour*		0.009076	0.005763	0.004403	0.004944	0.018140	0.006377	0.013549	0.002524
PM_{25} Annual		0.000752	0.000456	0.000386	0.000398	0.001223	0.000512	0.000840	0.000156
PM_{10} 24-Hour*	4.00	0.009323	0.005881	0.004473	0.005085	0.018540	0.006477	0.014018	0.002989
PM_{10} Annual	8.00	0.000796	0.000476	0.000401	0.000416	0.001288	0.000537	0.000876	0.000162
NO_2 Annual	2.50	0.000125	0.000090	0.000056	0.000088	0.000717	0.000156	0.000408	0.000010
2006									
SO_2 3-Hour*	25.00	0.000096	0.000074	0.000049	0.000089	0.000219	0.000153	0.000253	0.000024
SO_2 24-Hour*	5.00	0.000027	0.000021	0.000016	0.000027	0.000083	0.000035	0.000082	0.000008
SO_2 Annual	2.00	0.000003	0.000002	0.000001	0.000002	0.000009	0.000002	0.000006	0.000000
PM_{25} 24-Hour*		0.006821	0.005442	0.003137	0.005108	0.014317	0.006135	0.013876	0.001846
PM_{25} Annual		0.000630	0.000413	0.000316	0.000365	0.001347	0.000442	0.000968	0.000082
PM_{10} 24-Hour*	4.00	0.007046	0.005617	0.003218	0.005236	0.014909	0.006594	0.014093	0.001990
PM_{10} Annual	8.00	0.000665	0.000433	0.000330	0.000383	0.001434	0.000464	0.001029	0.000086
NO_2 Annual	2.50	0.000137	0.000087	0.000048	0.000083	0.000950	0.000125	0.000576	0.000005

*Highest second high at any monitor in the Class I area.

Table 19. CALPUFF Estimated PSD Pollutant Concentrations Impacts at Class I Areas for the Project plus the Cumulative Emissions, including RFD Sources. PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

Species and Averaging Time	PSD Class I Area Increment (μg/m3)	Concentration Estimates (μg/m^3)							
		Flat Tops	Maroon Bells	West Elk	Black Canyon	Arches	Capitol Reef	Canyon-lands	Bryce Canyon
2002									
SO_2 3-Hour*	25.00	0.0653	0.0364	0.0251	0.0407	0.1245	0.1328	0.1141	0.0199
SO_2 24-Hour*	5.00	0.0203	0.0134	0.0098	0.0184	0.0507	0.0488	0.0406	0.0096
SO_2 Annual	2.00	0.0045	0.0025	0.0014	0.0021	0.0076	0.0041	0.0073	0.0006
PM_{25} 24-Hour*	2.00	0.3277	0.2976	0.1797	0.2866	0.3135	0.0855	0.2393	0.0282
PM_{25} Annual	1.00	0.0584	0.0384	0.0195	0.0282	0.0268	0.0081	0.0178	0.0022
PM_{10} 24-Hour*	8.00	0.3334	0.3140	0.1833	0.2917	0.3173	0.0860	0.2417	0.0304
PM_{10} Annual	4.00	0.0646	0.0418	0.0201	0.0288	0.0274	0.0082	0.0182	0.0023
NO_2 Annual	2.50	0.1692	0.0436	0.0068	0.0107	0.2003	0.0036	0.0084	0.0001
2005									
SO_2 3-Hour*	25.00	0.0633	0.0339	0.0225	0.0695	0.1206	0.1519	0.1359	0.0191
SO_2 24-Hour*	5.00	0.0234	0.0129	0.0073	0.0144	0.0505	0.0627	0.0479	0.0106
SO_2 Annual	2.00	0.0041	0.0020	0.0012	0.0017	0.0079	0.0064	0.0079	0.0007
PM_{25} 24-Hour*	2.00	0.3586	0.1664	0.0850	0.1671	0.2407	0.0885	0.1981	0.0279
PM_{25} Annual	1.00	0.0432	0.0232	0.0129	0.0208	0.0257	0.0095	0.0178	0.0026
PM_{10} 24-Hour*	8.00	0.3649	0.1803	0.0879	0.1689	0.2480	0.0895	0.2034	0.0280
PM_{10} Annual	4.00	0.0490	0.0257	0.0135	0.0216	0.0265	0.0097	0.0183	0.0027
NO_2 Annual	2.50	0.1448	0.0321	0.0064	0.0097	0.1541	0.0036	0.0119	0.0001
2006									
SO_2 3-Hour*	25.00	0.0790	0.0368	0.0239	0.0375	0.1349	0.1560	0.1418	0.0135
SO_2 24-Hour*	5.00	0.0209	0.0124	0.0100	0.0113	0.0462	0.0468	0.0449	0.0063
SO_2 Annual	2.00	0.0042	0.0021	0.0013	0.0017	0.0068	0.0057	0.0079	0.0006
PM_{25} 24-Hour*	2.00	0.2343	0.2665	0.1230	0.1651	0.2348	0.0888	0.1956	0.0241
PM_{25} Annual	1.00	0.0456	0.0292	0.0161	0.0216	0.0250	0.0078	0.0172	0.0019
PM_{10} 24-Hour*	8.00	0.2535	0.2726	0.1289	0.1726	0.2406	0.0911	0.2015	0.0256
PM_{10} Annual	4.00	0.0514	0.0319	0.0169	0.0223	0.0259	0.0080	0.0177	0.0019
NO_2 Annual	2.50	0.1522	0.0378	0.0073	0.0089	0.1395	0.0040	0.0124	0.0002

*Highest second high at any monitor in the Class I area.

Table 20. CALPUFF Estimated PSD Pollutant Concentrations Impacts at Class I Areas for the Project plus the Cumulative Emissions without RFD Sources. PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

Species and Averaging Time	PSD Class I Area Increment (µg/m3)	Concentration Estimates (µg/m^3)							
		Flat Tops	Maroon Bells	West Elk	Black Canyon	Arches	Capitol Reef	Canyon-lands	Bryce Canyon
2002									
SO_2 3-Hour*	25.00	0.0290	0.0156	0.0230	0.0366	0.1245	0.1326	0.1141	0.0199
SO_2 24-Hour*	5.00	0.0086	0.0060	0.0071	0.0087	0.0502	0.0486	0.0385	0.0096
SO_2 Annual	2.00	0.0016	0.0010	0.0009	0.0013	0.0070	0.0040	0.0070	0.0006
PM_{25} 24-Hour*	2.00	0.1716	0.1074	0.0907	0.1219	0.1378	0.0636	0.1095	0.0246
PM_{25} Annual	1.00	0.0258	0.0136	0.0105	0.0183	0.0194	0.0065	0.0118	0.0017
PM_{10} 24-Hour*	8.00	0.1717	0.1074	0.0907	0.1220	0.1378	0.0640	0.1095	0.0249
PM_{10} Annual	4.00	0.0259	0.0137	0.0105	0.0183	0.0196	0.0066	0.0119	0.0017
NO_2 Annual	2.50	0.1502	0.0296	0.0047	0.0082	0.1986	0.0035	0.0072	0.0001
2005									
SO_2 3-Hour*	25.00	0.0344	0.0189	0.0151	0.0195	0.1206	0.1498	0.1358	0.0188
SO_2 24-Hour*	5.00	0.0097	0.0075	0.0065	0.0083	0.0505	0.0627	0.0478	0.0103
SO_2 Annual	2.00	0.0014	0.0009	0.0007	0.0010	0.0071	0.0062	0.0074	0.0007
PM_{25} 24-Hour*	2.00	0.1158	0.0581	0.0446	0.0928	0.1209	0.0687	0.0869	0.0221
PM_{25} Annual	1.00	0.0180	0.0091	0.0068	0.0139	0.0164	0.0076	0.0115	0.0019
PM_{10} 24-Hour*	8.00	0.1158	0.0583	0.0447	0.0929	0.1216	0.0692	0.0873	0.0222
PM_{10} Annual	4.00	0.0181	0.0092	0.0068	0.0139	0.0165	0.0077	0.0116	0.0019
NO_2 Annual	2.50	0.1254	0.0224	0.0038	0.0068	0.1517	0.0035	0.0105	0.0001
2006									
SO_2 3-Hour*	25.00	0.0375	0.0185	0.0142	0.0207	0.1349	0.1457	0.1417	0.0117
SO_2 24-Hour*	5.00	0.0084	0.0065	0.0054	0.0062	0.0448	0.0426	0.0449	0.0059
SO_2 Annual	2.00	0.0015	0.0009	0.0007	0.0010	0.0058	0.0055	0.0074	0.0005
PM_{25} 24-Hour*	2.00	0.0879	0.0632	0.0591	0.0741	0.0815	0.0468	0.0676	0.0139
PM_{25} Annual	1.00	0.0188	0.0104	0.0079	0.0139	0.0147	0.0060	0.0103	0.0013
PM_{10} 24-Hour*	8.00	0.0880	0.0633	0.0591	0.0742	0.0818	0.0471	0.0677	0.0141
PM_{10} Annual	4.00	0.0189	0.0104	0.0079	0.0139	0.0149	0.0061	0.0104	0.0013
NO_2 Annual	2.50	0.1311	0.0260	0.0042	0.0066	0.1366	0.0038	0.0108	0.0001

*Highest second high at any monitor in the Class I area.

The CALPUFF-estimated potential maximum concentration increments due to the Project with the cumulative emissions at any Class I area were combined with the existing maximum background concentrations (see Table 15) in the region to obtain a Total estimated concentration that is compared against the NAAQS, WAAQS, UAAQS, and CAAQS in Table 23. The maximum CALPUFF-estimated potential impacts due to the Project plus the cumulative sources occur at the Flat Tops, Arches, Canyonlands, Capitol Reef and Maroon Bells-Snowmass Class I Areas. Table 23 shows that when the Project plus the potential cumulative source impacts at any Class I area are added to the maximum background concentrations to obtain a total concentration, they do not exceed any applicable federal or state ambient air quality standards.

In summary, the modeling results indicate that neither direct Project impacts nor Project impacts taken together with cumulative source impacts would exceed any air quality standards (WAAQS, UAAQS, CAAQS, and NAAQS) or PSD Class I area increments. The PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

Table 21. Comparison of Maximum Existing Background Concentrations (Table 15) plus Maximum Estimated Impacts at any Class I Area Due to the Project plus Cumulative Sources (Including RFD) with Federal and State Ambient Air Quality Standards.

Pollutant / Averaging Time	Ambient Air Quality Standards (μg/m³)				Estimated Impact (μg/m³)		
	National	Wyoming	Colorado	Utah	Total	Bckgd[1]	Incmnt[2]
Nitrogen Dioxide (NO_2)							
Annual	100	100	100	100	**17**	17	0.20
PM_{10}							
24-hour	150	150	150	150	**67**	67	0.36
Annual	Revoked	50	50	50	**22**	21.8	0.06
$PM_{2.5}$							
24-hour	35	65	--	65	**NA**	NA	0.36
Annual	15	15	--	15	**NA**	NA	0.06
Sulfur Dioxide (SO_2)							
3-hour	1,300	1,300	7005	1,300	**20**	20	0.16
24-hour	365	260	1005	365	**10**	10	0.06
Annual	80	60	155	80	**5**	5	0.01

[1] Maximum current background concentration in the region (Table 15)
[2] Maximum Cumulative Emissions Plus Project increment concentration at any Class I area for any of the modeling years

4.5.6.2 Class II Area Far-Field Concentration Results

The maximum predicted concentrations of NO_2, SO_2, PM_{10}, and $PM_{2.5}$ at any receptor within each of the sensitive PSD Class II receptor areas for the Project are shown in Table 24. The highest estimated concentration impact at any Class II area occurs for 24-hour $PM_{2.5}$ at the High Uinta Wilderness Area, and is ~0.5% of the PSD Class II increment. No PSD Class II increment is exceeded at any Class II area for the Project scenario.

Table 25 displays the maximum estimated PSD pollutant concentrations at any receptor within each of the Class II areas due to the Project plus the cumulative emissions inventory and compares them to the PSD Class II increments. The highest estimated impacts due to the cumulative emissions plus the Project occur for the Brown Park NWR, Dinosaur National Monument and Colorado National Monument Class II Areas, whose impacts are:

- Less than 1% of the PSD Class II increments for annual, 24-hour and 3-hour SO2 concentrations;
- Less than 1% and 3% of the PSD Class II area increments for annual and 24-hour PM10, respectively; and
- Less than 1% of the PSD Class II area increment for annual NO2.

With the addition of the cumulative emissions to the Project emissions, these results show that the maximum air quality impacts for the Project taken together with the cumulative emission inventory would not exceed any PSD Class II increment at any Class II area.

In Table 26, the maximum estimated PSD pollutant concentrations at any receptor within each of the Class II areas due to the Project plus the cumulative emissions inventory without RFD sources are compared to the PSD Class II increments. As in the case in which the RFD was included in the cumulative emission inventory, the estimated air quality impacts due to the Project plus the cumulative emissions would not exceed any PSD Class II area increment at any Class II area. Comparison of Tables 25 and 26 shows that the impacts on Class II areas are slightly smaller when the effects of the RFD sources are removed.

Table 22. CALPUFF Estimated PSD Pollutant Concentrations Impacts at Class II Areas for the Project. PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

Species and Averaging Time	PSD Class II Area Increment (µg/m3)	Concentration Estimates (µg/m^3)							
		Holy Cross WA	High Uinta WA	Raggeds WA	Colorado NM	Brown Park NWR	Hunter Frying Pan WA	Flaming Gorge NRA	Dinosaur NM
2002									
SO_2 3-Hour*	512.00	0.000042	0.000228	0.000049	0.000220	0.000169	0.000038	0.000160	0.000547
SO_2 24-Hour*	91.00	0.000011	0.000096	0.000018	0.000062	0.000051	0.000013	0.000045	0.000163
SO_2 Annual	20.00	0.000002	0.000013	0.000002	0.000007	0.000010	0.000001	0.000009	0.000027
PM_{25} 24-Hour*	9.00	0.003254	0.044002	0.005379	0.020408	0.013856	0.003536	0.020171	0.031952
PM_{25} Annual	4.00	0.000399	0.004347	0.000485	0.001410	0.002366	0.000368	0.002627	0.005747
PM_{10} 24-Hour*	30.00	0.003270	0.044286	0.005553	0.020660	0.014528	0.003632	0.020352	0.032625
PM_{10} Annual	17.00	0.000420	0.004540	0.000504	0.001488	0.002506	0.000386	0.002753	0.006135
NO_2 Annual	25.00	0.000036	0.000783	0.000039	0.000610	0.000601	0.000035	0.000382	0.002804
2005									
SO_2 3-Hour*	512.00	0.000043	0.000260	0.000073	0.000186	0.000168	0.000044	0.000116	0.000562
SO_2 24-Hour*	91.00	0.000015	0.000110	0.000018	0.000059	0.000056	0.000017	0.000052	0.000178
SO_2 Annual	20.00	0.000001	0.000010	0.000002	0.000007	0.000010	0.000001	0.000007	0.000031
PM_{25} 24-Hour*	9.00	0.004101	0.048298	0.005173	0.012849	0.015467	0.003801	0.026216	0.035682
PM_{25} Annual	4.00	0.000329	0.003002	0.000447	0.001216	0.001996	0.000302	0.001902	0.005569
PM_{10} 24-Hour*	30.00	0.004306	0.048814	0.005454	0.013330	0.015563	0.003942	0.026517	0.036019
PM_{10} Annual	17.00	0.000345	0.003132	0.000465	0.001290	0.002137	0.000315	0.001996	0.006007
NO_2 Annual	25.00	0.000045	0.000689	0.000079	0.000591	0.000736	0.000045	0.000342	0.004087
2006									
SO_2 3-Hour*	512.00	0.000060	0.000255	0.000039	0.000224	0.000175	0.000052	0.000130	0.000563
SO_2 24-Hour*	91.00	0.000014	0.000059	0.000014	0.000068	0.000056	0.000014	0.000040	0.000178
SO_2 Annual	20.00	0.000001	0.000008	0.000002	0.000007	0.000009	0.000001	0.000007	0.000028
PM_{25} 24-Hour*	9.00	0.004133	0.021627	0.005134	0.013680	0.014000	0.003551	0.014290	0.035373
PM_{25} Annual	4.00	0.000309	0.001929	0.000370	0.001079	0.001816	0.000281	0.001488	0.004942
PM_{10} 24-Hour*	30.00	0.004254	0.021710	0.005410	0.013978	0.014306	0.003658	0.014445	0.037300
PM_{10} Annual	17.00	0.000325	0.002030	0.000387	0.001150	0.001959	0.000295	0.001592	0.005353
NO_2 Annual	25.00	0.000046	0.000379	0.000062	0.000633	0.000719	0.000048	0.000327	0.003499

*Highest second high at any monitor in the Class II area.

Table 23. CALPUFF Estimated PSD Pollutant Concentrations Impacts at Class II Areas for the Project plus the Cumulative Emissions with RFD Sources. PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

Species and Averaging Time	PSD Class II Area Increment (μg/m3)	Concentration Estimates (μg/m^3)							
		Holy Cross WA	High Uinta WA	Raggeds WA	Colorado NM	Brown Park NWR	Hunter Frying Pan WA	Flaming Gorge NRA	Dinosaur NM
2002									
SO_2 3-Hour*	512.00	0.033129	0.099231	0.027640	0.362990	0.129800	0.029647	0.056583	0.235650
SO_2 24-Hour*	91.00	0.010559	0.026589	0.010499	0.076675	0.049702	0.009778	0.029791	0.052297
SO_2 Annual	20.00	0.001900	0.004731	0.001715	0.009728	0.006522	0.001488	0.004137	0.011049
PM_{25} 24-Hour*	9.00	0.165750	0.248660	0.177420	0.538600	0.757480	0.151420	0.594520	0.751970
PM_{25} Annual	4.00	0.026572	0.027727	0.028345	0.076229	0.055306	0.020647	0.034299	0.103020
PM_{10} 24-Hour*	30.00	0.168730	0.252010	0.184240	0.560830	0.767880	0.153080	0.597190	0.761600
PM_{10} Annual	17.00	0.028011	0.034979	0.029741	0.078619	0.058504	0.021659	0.036133	0.106100
NO_2 Annual	25.00	0.012300	0.040910	0.019015	0.057375	0.166040	0.008672	0.043911	0.177780
2005									
SO_2 3-Hour*	512.00	0.028087	0.087920	0.022431	0.446110	0.141600	0.027084	0.067617	0.266880
SO_2 24-Hour*	91.00	0.009222	0.039983	0.008819	0.095543	0.062410	0.009111	0.027675	0.070520
SO_2 Annual	20.00	0.001638	0.004417	0.001464	0.009134	0.006683	0.001243	0.004029	0.012844
PM_{25} 24-Hour*	9.00	0.136920	0.304850	0.109910	0.367210	0.790930	0.096886	0.558120	0.785150
PM_{25} Annual	4.00	0.017593	0.021792	0.019754	0.063725	0.053683	0.013394	0.033935	0.092363
PM_{10} 24-Hour*	30.00	0.140050	0.315420	0.110920	0.375800	0.797940	0.101860	0.562180	0.792080
PM_{10} Annual	17.00	0.018730	0.027678	0.021055	0.066595	0.056484	0.014167	0.035507	0.095405
NO_2 Annual	25.00	0.010063	0.031472	0.016839	0.058266	0.169570	0.006998	0.047128	0.169760
2006									
SO_2 3-Hour*	512.00	0.023627	0.086557	0.031758	0.212380	0.084426	0.026082	0.040126	0.242360
SO_2 24-Hour*	91.00	0.009663	0.023551	0.010579	0.046838	0.032453	0.007914	0.016534	0.060241
SO_2 Annual	20.00	0.001668	0.003805	0.001609	0.008184	0.006224	0.001262	0.003690	0.010833
PM_{25} 24-Hour*	9.00	0.144730	0.113040	0.157070	0.338420	0.354060	0.160490	0.221130	0.438010
PM_{25} Annual	4.00	0.019342	0.018384	0.023442	0.057698	0.044282	0.015534	0.027868	0.086847
PM_{10} 24-Hour*	30.00	0.146340	0.120790	0.162890	0.343850	0.358180	0.163230	0.223440	0.444800
PM_{10} Annual	17.00	0.020495	0.024771	0.025116	0.060705	0.047369	0.016460	0.029592	0.089732
NO_2 Annual	25.00	0.009483	0.031616	0.019529	0.053737	0.175040	0.007773	0.041456	0.168680

*Highest second high at any monitor in the Class II area.

Table 24. CALPUFF Estimated PSD Pollutant Concentrations Impacts at Class II Areas for the Project plus the Cumulative Emissions without RFD Sources. PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

Species and Averaging Time	PSD Class II Area Increment (µg/m3)	Concentration Estimates (µg/m^3)							
		Holy Cross WA	High Uinta WA	Raggeds WA	Colorado NM	Brown Park NWR	Hunter Frying Pan WA	Flaming Gorge NRA	Dinosaur NM
2002									
SO_2 3-Hour*	512.00	0.010638	0.099142	0.015561	0.351220	0.065434	0.011546	0.051729	0.065261
SO_2 24-Hour*	91.00	0.004604	0.026469	0.006778	0.076641	0.014551	0.004396	0.021149	0.018923
SO_2 Annual	20.00	0.000822	0.004501	0.000941	0.007344	0.002936	0.000698	0.002799	0.004622
PM_{25} 24-Hour*	9.00	0.056741	0.153020	0.084965	0.279150	0.149300	0.048359	0.148360	0.344490
PM_{25} Annual	4.00	0.009186	0.021710	0.014805	0.050847	0.020824	0.007611	0.017142	0.065296
PM_{10} 24-Hour*	30.00	0.056757	0.153180	0.084977	0.279460	0.149390	0.048388	0.148440	0.344510
PM_{10} Annual	17.00	0.009218	0.021943	0.014839	0.050969	0.021048	0.007639	0.017320	0.065460
NO_2 Annual	25.00	0.004254	0.039737	0.013759	0.040997	0.038558	0.003204	0.017140	0.159780
2005									
SO_2 3-Hour*	512.00	0.017303	0.087918	0.016372	0.445690	0.046609	0.013570	0.054011	0.045602
SO_2 24-Hour*	91.00	0.006102	0.039752	0.006654	0.086421	0.016299	0.005573	0.019536	0.016061
SO_2 Annual	20.00	0.000774	0.004189	0.000783	0.006648	0.002665	0.000620	0.002469	0.003963
PM_{25} 24-Hour*	9.00	0.045425	0.208590	0.063156	0.209300	0.138990	0.033687	0.153970	0.258520
PM_{25} Annual	4.00	0.006727	0.015563	0.010653	0.041498	0.019606	0.005390	0.013761	0.052635
PM_{10} 24-Hour*	30.00	0.045459	0.209040	0.063500	0.209350	0.139120	0.033711	0.154080	0.258690
PM_{10} Annual	17.00	0.006751	0.015734	0.010680	0.041610	0.019817	0.005411	0.013921	0.052820
NO_2 Annual	25.00	0.003705	0.030434	0.011177	0.039246	0.041085	0.002718	0.015538	0.138830
2006									
SO_2 3-Hour*	512.00	0.012905	0.086557	0.014653	0.209160	0.022989	0.009765	0.032579	0.057297
SO_2 24-Hour*	91.00	0.004734	0.022888	0.005508	0.039205	0.008983	0.004379	0.011685	0.016759
SO_2 Annual	20.00	0.000738	0.003566	0.000736	0.005607	0.002410	0.000589	0.002201	0.004063
PM_{25} 24-Hour*	9.00	0.044736	0.081561	0.085551	0.170290	0.073974	0.049093	0.076956	0.303420
PM_{25} Annual	4.00	0.007137	0.013101	0.011485	0.035180	0.016542	0.005831	0.011993	0.051321
PM_{10} 24-Hour*	30.00	0.044752	0.081608	0.085592	0.170300	0.074031	0.049094	0.076975	0.304110
PM_{10} Annual	17.00	0.007160	0.013243	0.011511	0.035279	0.016757	0.005852	0.012161	0.051521
NO_2 Annual	25.00	0.003780	0.030215	0.013170	0.035709	0.041283	0.003082	0.013780	0.135690

*Highest second high at any monitor in the Class II area.

The CALPUFF-estimated potential maximum concentration due to the Project with the cumulative emissions at any Class II area were combined with the existing maximum background concentrations (see Table 15) in the region to obtain a total estimated concentration that is compared against the NAAQS, WAAQS, UAAQS, and CAAQS in Table 27. The maximum CALPUFF-estimated potential impacts due to the Project plus the cumulative sources always occurred at the Brown Park NWR, Dinosaur National Monument and Colorado National Monument Class II Areas. Table 27 shows that when the Project plus the cumulative source potential impacts at any Class II area are added to the maximum background concentrations to obtain a total concentration they would not exceed any federal or state ambient air quality standards.

Table 25. Comparison Of Maximum Existing Background Concentrations (Table 15) Plus Maximum Estimated Impacts At Any Class II Area Due To the Project Plus Cumulative Sources With Federal And State Ambient Air Quality Standards.

Pollutant / Averaging Time	Ambient Air Quality Standards ($\mu g/m^3$)				Estimated Impact ($\mu g/m^3$)		
	National	Wyoming	Colorado	Utah	Total	Bckgd[1]	Incmnt[2]
Nitrogen Dioxide (NO_2)							
Annual	100	100	100	100	**17.2**	17	0.18
PM_{10}							
24-hour	150	150	150	150	**68**	67	0.80
Annual	Revoked	50	50	50	**22**	21.8	0.11
$PM_{2.5}$							
24-hour	35	65	--	65	**NA**	NA	0.79
Annual	15	15	--	15	**NA**	NA	0.10
Sulfur Dioxide (SO_2)							
3-hour	1,300	1,300	7005	1,300	**20**	20	0.45
24-hour	365	260	1005	365	**10**	10	0.10
Annual	80	60	155	80	**5.0**	5	0.01

[1] Maximum current background concentration in the region (Table 4-5)

[2] Maximum Cumulative Emissions Plus Project increment concentration at any Class II area for any of the modeling years.

In summary, the modeling results indicate that neither potential direct Project impacts nor potential Project impacts taken together with cumulative source impacts would exceed any air quality standards (WAAQS, UAAQS, CAAQS, and NAAQS) or PSD Class II area increments. The PSD demonstrations are for informational purposes only and do not constitute a regulatory PSD increment consumption analysis.

4.5.7 Sulfur and Nitrogen Deposition

Maximum predicted potential sulfur (S) and nitrogen (N) deposition impacts were estimated for the Project and cumulative source scenario. The POSTUTIL utility was used to estimate total S and N fluxes from CALPUFF predicted wet and dry fluxes of SO_2, SO_4, NOx, NO_3, and HNO_3. Note that the N associated with Ammonium (NH_4) that is assumed to be bound to SO_4 and NO_3 was also included in the N deposition. CALPOST was then used to summarize the annual S and N deposition values from the POSTUTIL program. The maximum total annual S and N deposition at any receptor in each Class I and Class II area was reported. Total deposition impacts from the Project and regional sources and background values were compared to USDA Forest Service levels of concern, defined as 5 kg/ha-yr for S and 3 kg/ha-yr for N (Fox et al. 1989). It is understood that the USDA Forest Service no longer considers these levels protective; however, in the absence of alternative FLM-approved values, comparisons with these values were made. At the request of the USDA Forest Service, comparisons were also made with the National Park Service Deposition Analysis Thresholds (DATs). The maximum predicted total annual N and S deposition impacts at Class I areas for the Project are given in Table 28, and the maximum total annual N and S deposition due to the Project combined with the cumulative emissions are provided in Table 29. Modeling results for the Project alone indicate there are no direct Project total N or S deposition impacts above the Forest Service levels of concern or the NPS DATs. The largest impacts are at Arches National Park, with the maximum impact less than 0.02% (0.0002%) of the Forest Service level of concern and ~9% (~0.07%) of the NPS DAT for nitrogen (sulfur).

For the Project plus the Cumulative Emissions, the estimated sulfur deposition is far below (<0.1%) the Forest Service 3.0 kg/ha/yr level of concern and below the NPS DAT for all three years of modeling at all Class I areas. The maximum estimated annual nitrogen at any Class I area for the Project plus Cumulative Emissions occurs at the Flat Tops Class I area with values near 0.05 kg/ha/yr estimated for the Project combined with Cumulative Emissions (including RFD sources) for all three modeled years. These maximum nitrogen deposition impacts are approximately a factor of 100 lower than the Forest Service 3.0 kg/ha/yr level of concern, but exceed the NPS DAT for nitrogen by approximately an order of magnitude.

When RFD emissions are removed from the cumulative inventory (Table 30), the sulfur deposition remains far below the Forest Service 3.0 kg/ha/yr level of concern and the NPS DAT for all years and all Class I areas. Maximum estimated annual nitrogen impacts of approximately 0.03 kg/ha/yr occur at the Flat Tops Class I Area during all three modeled years. All maximum nitrogen deposition values are a factor of 100 lower than the Forest Service 3.0 kg/ha/yr level of concern, but exceed the NPS DAT for nitrogen by an roughly an order of magnitude .

Table 26. Maximum Nitrogen and Sulfur Deposition (Kg/Ha/Yr) in Class I Areas for Three-Year CALPUFF Modeling for the Project Alone.

	Total Deposition	N (kg/ha-yr)	S (kg/ha-yr)
	FS Threshold	**3**	**5**
	NPS DAT	**0.005**	**0.005**
Flat Tops			
	2002	0.00039	2.74E-06
	2005	0.00041	3.17E-06
	2006	0.00035	2.63E-06
Maroon Bells-			
Snowmass	2002	0.00023	1.47E-06
	2005	0.00024	1.65E-06
	2006	0.00017	1.34E-06
West Elk			
	2002	0.00015	1.08E-06
	2005	0.00016	1.17E-06
	2006	0.00015	1.26E-06
Black Canyon			
of the	2002	0.00019	1.32E-06
Gunnison	2005	0.00018	1.30E-06
	2006	0.00019	1.51E-06
Arches			
	2002	0.00046	3.16E-06
	2005	0.00036	2.78E-06
	2006	0.00046	3.57E-06
Capitol Reef			
	2002	0.00006	5.28E-07
	2005	0.00013	1.04E-06
	2006	0.00009	8.34E-07
Canyonlands			
	2002	0.00025	1.85E-06
	2005	0.00023	1.75E-06
	2006	0.00033	2.42E-06
Bryce Canyon			
	2002	0.00002	2.48E-07
	2005	0.00004	3.96E-07
	2006	0.00003	2.69E-07

Table 27. Maximum Nitrogen and Sulfur Deposition (kg/ha/yr) in the Class I Areas for Three-Years of CALPUFF Modeling for the Project and Cumulative Emissions including RFD Sources.

	Total Deposition	N (kg/ha-yr)	S (kg/ha-yr)
	FS Threshold	3	5
	NPS DAT	0.005	0.005
Flat Tops			
	2002	0.0521	0.0035
	2005	0.0493	0.0038
	2006	0.0488	0.0034
Maroon Bells-			
Snowmass	2002	0.0186	0.0017
	2005	0.0144	0.0015
	2006	0.0152	0.0014
West Elk			
	2002	0.0060	0.0011
	2005	0.0058	0.0009
	2006	0.0065	0.0011
Black Canyon			
of the	2002	0.0074	0.0014
Gunnison	2005	0.0076	0.0012
	2006	0.0070	0.0013
Arches			
	2002	0.0209	0.0025
	2005	0.0191	0.0029
	2006	0.0177	0.0027
Capitol Reef			
	2002	0.0014	0.0011
	2005	0.0022	0.0022
	2006	0.0019	0.0017
Canyonlands			
	2002	0.0035	0.0021
	2005	0.0051	0.0025
	2006	0.0051	0.0026
Bryce Canyon			
	2002	0.0005	0.0004
	2005	0.0007	0.0005
	2006	0.0005	0.0004

Table 28. Maximum Nitrogen and Sulfur Deposition (kg/ha/yr) in the Class I Areas for Three-Years of CALPUFF Modeling for the Project and Cumulative Emissions with no RFD Sources.

	Total Deposition	N (kg/ha-yr)	S (kg/ha-yr)
	FS Threshold	3	5
	NPS DAT	0.005	0.005
Flat Tops			
	2002	0.0371	0.0013
	2005	0.0341	0.0014
	2006	0.0343	0.0013
Maroon Bells-			
Snowmass	2002	0.0093	0.0008
	2005	0.0077	0.0008
	2006	0.0080	0.0007
West Elk			
	2002	0.0034	0.0007
	2005	0.0029	0.0006
	2006	0.0031	0.0006
Black Canyon			
of the	2002	0.0046	0.0009
Gunnison	2005	0.0041	0.0007
	2006	0.0041	0.0009
Arches			
	2002	0.0195	0.0022
	2005	0.0170	0.0026
	2006	0.0152	0.0023
Capitol Reef			
	2002	0.0010	0.0010
	2005	0.0018	0.0021
	2006	0.0014	0.0016
Canyonlands			
	2002	0.0025	0.0020
	2005	0.0034	0.0023
	2006	0.0033	0.0024
Bryce Canyon			
	2002	0.0003	0.0004
	2005	0.0005	0.0005
	2006	0.0004	0.0004

The maximum predicted total annual N and S deposition impacts at Class II areas for the Project alone are given in Table 31. Modeling results for the Project indicate there are no direct Project total N or S deposition impacts above the Forest Service levels of concern or the NPS DATs. The largest impacts are at the Dinosaur National Monument Class II Area, with the maximum impact less than 0.08% (0.0003%) of the Forest Service level of concern and ~42% (~0.3%) of the NPS DAT for nitrogen (sulfur).

For the Project plus the cumulative emissions (Table 32), the estimated sulfur and nitrogen deposition is below the Forest Service level of concern for all sites and all years. Maximum estimated annual sulfur deposition is below the NPS DAT for all Class II Areas except Dinosaur National Monument, where the maximum estimated sulfur deposition is 0.0075 kg/ha/yr. The maximum estimated annual nitrogen at any Class II area also occurs at the Dinosaur National Monument Class II area with a value of 0.0595 kg/ha/yr estimated for the Project combined with cumulative emissions including RFD sources. This value corresponds to approximately 2% of the Forest Service 3.0 kg/ha/yr level of concern and exceeds the NPS DAT by approximately an order of magnitude.

When RFD sources are removed from the cumulative emissions inventory (Table 33), the estimated nitrogen and sulfur deposition remain below (<1%) the Forest Service level of concern for all sites and all years. For sulfur, the NPS DAT is not exceeded at any site, with maximum estimated sulfur deposition of 0.0037 (74% of the DAT) at the High Uinta Class II Area. The maximum estimated annual nitrogen at any Class II area also occurs at the Dinosaur National Monument Class II area with a value of 0.025 kg/ha/yr estimated for the Project combined with cumulative emissions including RFD sources. This value corresponds to approximately 1% of the Forest Service 3.0 kg/ha/yr level of concern and exceeds the NPS DAT. Overall, removal of the RFD sources from the cumulative emission inventory reduces sulfur and nitrogen deposition impacts.

Table 29. Maximum Nitrogen and Sulfur Deposition (Kg/Ha/Yr) In the Class II Areas for Three Year CALPUFF Modeling for the Project Alone.

	Total Deposition	**N (kg/ha-yr)**	**S (kg/ha-yr)**
	FS Threshold	**3**	**5**
	NPS DAT	**0.005**	**0.005**
Brown Park			
	2002	0.00078	5.54E-06
	2005	0.00095	6.60E-06
	2006	0.00072	5.57E-06
Colorado			
National	2002	0.00051	3.69E-06
Monument	2005	0.00057	4.46E-06
	2006	0.00052	4.00E-06
Dinosaur			
National	2002	0.00135	9.75E-06
Monument	2005	0.00205	1.36E-05
	2006	0.00162	1.16E-05
Flaming Gorge			
	2002	0.00060	5.00E-06
	2005	0.00065	4.87E-06
	2006	0.00052	4.52E-06
Hunter Frying			
Pan	2002	0.00018	1.09E-06
	2005	0.00019	1.23E-06
	2006	0.00014	1.06E-06
Holy Cross			
	2002	0.00017	1.13E-06
	2005	0.00016	1.14E-06
	2006	0.00013	1.04E-06
High Uinta			
	2002	0.00072	6.21E-06
	2005	0.00084	5.99E-06
	2006	0.00062	4.77E-06
Raggeds			
	2002	0.00020	1.35E-06
	2005	0.00021	1.47E-06
	2006	0.00016	1.30E-06

Table 30. Maximum Nitrogen and Sulfur Deposition (Kg/Ha/Yr) In the Class II Areas for Three-Year CALPUFF Modeling for the Project and Cumulative Emissions including RFD.

	Total Deposition	**N (kg/ha-yr)**	**S (kg/ha-yr)**
	FS Threshold	**3**	**5**
	NPS DAT	**0.005**	**0.005**
Brown Park NWR			
	2002	0.0466	0.0033
	2005	0.0497	0.0037
	2006	0.0531	0.0037
Colorado NM			
	2002	0.0205	0.0047
	2005	0.0218	0.0047
	2006	0.0216	0.0043
Dinosaur NM			
	2002	0.0486	0.0056
	2005	0.0595	0.0074
	2006	0.0566	0.0063
Flaming Gorge NRA			
	2002	0.0178	0.0024
	2005	0.0203	0.0026
	2006	0.0211	0.0025
Hunter Frying Pan WA			
	2002	0.0091	0.0011
	2005	0.0082	0.0011
	2006	0.0081	0.0010
Holy Cross WA			
	2002	0.0104	0.0013
	2005	0.0093	0.0012
	2006	0.0078	0.0011
High Uinta WA			
	2002	0.0109	0.0036
	2005	0.0103	0.0038
	2006	0.0110	0.0032
Raggeds WA			
	2002	0.0106	0.0013
	2005	0.0094	0.0012
	2006	0.0108	0.0013

Table 31. Maximum Nitrogen and Sulfur Deposition (Kg/Ha/Yr) In the Class II Areas for Three-Year CALPUFF Modeling for the Project and Cumulative Emissions with No RFD.

	Total Deposition	N (kg/ha-yr)	S (kg/ha-yr)
	FS Threshold	3	5
	NPS DAT	0.005	0.005
Brown Park NWR			
	2002	0.0115	0.0017
	2005	0.0132	0.0018
	2006	0.0128	0.0017
Colorado NM			
	2002	0.0134	0.0036
	2005	0.0140	0.0035
	2006	0.0128	0.0030
Dinosaur NM			
	2002	0.0231	0.0020
	2005	0.0250	0.0024
	2006	0.0236	0.0023
Flaming Gorge NRA			
	2002	0.0072	0.0018
	2005	0.0074	0.0018
	2006	0.0069	0.0017
Hunter Frying Pan WA			
	2002	0.0034	0.0006
	2005	0.0032	0.0006
	2006	0.0031	0.0005
Holy Cross WA			
	2002	0.0039	0.0007
	2005	0.0035	0.0007
	2006	0.0031	0.0006
High Uinta WA			
	2002	0.0095	0.0035
	2005	0.0090	0.0037
	2006	0.0087	0.0030
Raggeds WA			
	2002	0.0058	0.0008
	2005	0.0049	0.0007
	2006	0.0054	0.0006

4.5.8 Acid Neutralizing Capacity Calculations for Sensitive Lakes

The CALPUFF-estimated annual deposition fluxes of S and N at sensitive lake receptors were used to estimate the change in Acid Neutralizing Capacity (ANC). The change in ANC was calculated following the January 2000, USDA Forest Service Rocky Mountain Region's *Screening Methodology for Calculating ANC Change to High Elevation Lakes, User's Guide* (USDA Forest Service 2000). The predicted changes in ANC were compared with the USDA Forest Service's Level of Acceptable Change (LAC) thresholds of 10% for lakes with ANC values greater than 25 microequivalents per liter (μeq/l) and 1 μeq/l for lakes with background ANC values of 25 μeq/l or less. Of the lakes in the study area identified by the USDA Forest Service as acid sensitive, none of the lakes are considered extremely acid sensitive as all have ANC values greater than 25 μeq/l (see Table 19).

ANC calculations were performed for the Project plus cumulative emissions (including RFD sources), with the results presented in Table 34. For the five sensitive lakes with background ANC above 25 μeq/l, for which a change in ANC above 10% is a concern, the maximum changes in ANC are estimated to range from 0.09% to 0.25%. The deposition impacts from direct Project and cumulative emissions would not contribute significantly to an increase in acidification at any of the five sensitive lakes. Therefore, the Project plus the cumulative emissions are estimated to have no detrimental impact on lake acidity at any lake in the region.

Table 32. Lake Acid Neutralizing Capacity (ANC) Calculations for the Project plus Cumulative Emissions including RFD.

Lake	10% ANC (ueq/l)	Watershed Catchment Size (ha)	Annual Avg. Precip (in)	Ds(kg/ha/yr)	Dn(kg/ha/yr)	ANC(o)(eq)	Hdep(eq)	% ANC change	ANC change (ueq/l)
Bluebell Lake	56.1	153	40.2	0.0022	0.0095	58741	125.3	0.21%	0.080
Dean Lake	44.7	117	40.2	0.0028	0.0083	35787	90.3	0.25%	0.076
Fish Lake	96.9	308	40.2	0.0019	0.0066	204073	181.7	0.09%	0.058
No Name Lake	54.9	174	40.2	0.0022	0.0076	65399	118.4	0.18%	0.067
Walkup Lake	54.7	146	40.2	0.0019	0.0069	54616	89.4	0.16%	0.060

4.5.9 Visibility

The CALPUFF model-predicted potential concentration impacts at far-field PSD Class I receptors were post-processed with CALPOST to estimate potential impacts to visibility (regional haze) for the Project and cumulative sources for comparison to visibility impact thresholds. CALPOST-estimated visibility impacts were derived from predicted concentrations of PMC, PMF, SO_4, and NO_3 using the original IMPROVE reconstructed mass extinction equation (Malm, et al., 2000) as recommended by FLAG (2000) and EPA (2003a, b).

Change in atmospheric light extinction relative to background conditions is used to measure regional haze. Analysis thresholds for atmospheric light extinction are set forth in FLAG (2000); results are reported as a percent change in light extinction over natural background conditions. The thresholds of concern are defined as 5% and 10% changes over the reference background visibility for Project sources alone and cumulative source impacts, respectively. Potential visibility impacts are also expressed as a change in deciviews (dv) over natural background where a 1.0 and 0.5 change in dv is essentially numerically equal to a 10% and 5% change in extinction over natural background. The BLM considers a 1.0 dv change to be a significant adverse impact; however, there are no applicable local, state, tribal, or federal regulatory visibility standards. Lastly, the reader should be aware that Class II areas have no visibility protection under Federal, Tribal, State, or local law. The inclusion of sensitive Class II areas in this analysis was done at the request of the FLMs.

4.5.9.1 Visibility Assessment Methods

As discussed in Section 4.5.2, several visibility assessment methods were used to analyze the potential visibility impacts from the Project and from the Project plus the cumulative emissions. These methods differ on what background natural conditions are used (FLAG, IMPROVE or EPA Default) and whether hourly (MVISBK=2) or monthly (MVISBK=6) relative humidity adjustment factors in CALPOST [f(RH)] are used.

4.5.9.2 Visibility Impacts on Class I Areas due to the Project Alone

Table 35 lists the CALPUFF-estimated visibility impacts at the Class I areas due to the Project alone using the two calculation methods described above. The Project caused no impacts above either the 1.0 or 0.5 dv threshold during the three-year modeling period and therefore showed no detrimental impacts.

Table 33**.** CALPUFF-Estimated Visibility Impacts on Class I Areas for the Project Alone using Methods 2 and 6.

	Method Visibility = 2			Method Visibility = 6		
	# Days ≥ 0.5 dv	**# Days ≥ 1.0 dv**	**Max (dv)**	**# Days ≥ 0.5 dv**	**# Days ≥ 1.0 dv**	**Max (dv)**
Flat Tops	0					
2002	0	0	0.070	0	0	0.028
2005	0	0	0.064	0	0	0.039
2006	0	0	0.051	0	0	0.052
Maroon Bells	0					
2002	0	0	0.046	0	0	0.025
2005	0	0	0.028	0	0	0.032
2006	0	0	0.036	0	0	0.022
West Elk	0					
2002	0	0	0.032	0	0	0.029
2005	0	0	0.038	0	0	0.035
2006	0	0	0.061	0	0	0.030
Black Canyon	0					
2002	0	0	0.050	0	0	0.047
2005	0	0	0.024	0	0	0.021
2006	0	0	0.087	0	0	0.050
Arches	0					
2002	0	0	0.402	0	0	0.227
2005	0	0	0.115	0	0	0.095
2006	0	0	0.075	0	0	0.101
Capitol Reef	0					
2002	0	0	0.039	0	0	0.049
2005	0	0	0.069	0	0	0.030
2006	0	0	0.048	0	0	0.044
Canyonlands	0					
2002	0	0	0.273	0	0	0.111
2005	0	0	0.123	0	0	0.065
2006	0	0	0.122	0	0	0.061
Bryce Canyon	0					
2002	0	0	0.029	0	0	0.020
2005	0	0	0.015	0	0	0.011
2006	0	0	0.015	0	0	0.012

max visibility impact at any receptor (24-hour average)

4.5.9.3 Visibility Impacts on Class I Areas due to the Cumulative Emissions plus the Project

Table 36 lists the visibility impacts for the Cumulative Emissions plus the proposed Project including RFD sources. The largest impacts occur at the Flat Tops, Maroon Bells-Snowmass and Arches Class I Areas when the cumulative emissions are included. With the cumulative emissions added to the Project emissions, both Method 2 and Method 6 produce days that exceed the 1.0 dv threshold, with Method 2 producing more days over the 1.0 dv threshold than Method 6. For example, using Method 2, the 1.0 dv threshold is estimated to be exceeded for 35, 11 and 9 days at the Flat Tops, Maroon Bells-Snowmass and Arches Class I Areas, respectively, during the three modeled years. Using Method 6, the 1.0 dv threshold is estimated to be exceeded for 9, 1, and 2 days at the Flat Tops, Maroon Bells-Snowmass and Arches Class I Areas. Therefore, when the cumulative emission inventory including RFD sources is added to the Project emissions, the CALPUFF modeling showed potential detrimental impacts at several Class I areas.

Table 34**.** CALPUFF-Estimated Visibility Impacts on Class I Areas for the Project and Cumulative Emissions Including RFD using Method 2 and Method 6.

	Method Visibility = 2			Method Visibility = 6		
	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)
Flat Tops	0					
2002	61	23	2.318	43	6	1.429
2005	30	6	2.985	16	3	1.521
2006	32	6	1.572	21	0	0.965
Maroon Bells						
2002	27	6	2.049	15	1	1.079
2005	6	1	1.341	2	0	0.766
2006	14	4	1.523	9	0	0.991
West Elk						
2002	5	0	0.777	4	0	0.666
2005	0	0	0.462	0	0	0.346
2006	7	1	1.215	0	0	0.445
Black Canyon						
2002	8	0	0.901	10	2	1.002
2005	4	0	0.879	1	0	0.745
2006	5	1	1.382	3	0	0.582
Arches						
2002	22	6	1.432	17	2	1.131
2005	22	3	2.127	14	0	0.962
2006	11	0	0.859	7	0	0.925
Capitol Reef						
2002	0	0	0.464	0	0	0.468
2005	2	0	0.626	0	0	0.410
2006	0	0	0.427	0	0	0.442
Canyonlands						
2002	7	2	1.066	5	0	0.860
2005	8	2	1.665	7	0	0.781
2006	7	0	0.848	5	0	0.809
Bryce Canyon						
2002	0	0	0.315	0	0	0.189
2005	0	0	0.231	0	0	0.152
2006	0	0	0.120	0	0	0.146

max visibility impact at any receptor (24-hour average)

4.5.9.4 Visibility Impacts on Class I Areas due to the Project plus the Cumulative Emissions without RFD

Table 37 lists the visibility impacts for the cumulative emissions without the RFD sources plus the proposed Project. Using Method 6, the 1.0 dv threshold is not exceeded for any Class I area. Using Method 2, the method that shows larger potential impacts overall, the 1.0 dv threshold is estimated to be exceeded for 6 and 5 days at the Flat Tops and Arches Class I Areas. For all other Class I areas, visibility impacts did not exceed 1.0 dv on any day during the three year period using either method. Comparison with Table 36 shows that removing the RFD sources from the cumulative inventory reduces the visibility impacts, and if Method 6 is used, impacts are reduced to a sufficient degree that no detrimental impacts are indicated for any Class I area.

Table 35**.** CALPUFF-Estimated Visibility Impacts on Class I Areas for the Cumulative Emissions plus Project without RFD Sources using Method 2 and Method 6.

	Method Visibility = 2			Method Visibility = 6		
	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)
Flat Tops	0					
2002	30	4	1.361	5	0	0.737
2005	8	2	1.842	2	0	0.867
2006	3	0	0.753	0	0	0.432
Maroon Bells	0					
2002	3	0	0.736	0	0	0.497
2005	1	0	0.760	0	0	0.408
2006	1	0	0.565	0	0	0.289
West Elk	0					
2002	0	0	0.475	0	0	0.348
2005	0	0	0.181	0	0	0.140
2006	0	0	0.399	0	0	0.191
Black Canyon	0					
2002	0	0	0.466	1	0	0.512
2005	0	0	0.337	0	0	0.250
2006	0	0	0.478	0	0	0.247
Arches	0					
2002	15	4	1.424	10	0	0.652
2005	15	1	1.090	5	0	0.631
2006	5	0	0.851	0	0	0.364
Capitol Reef	0					
2002	0	0	0.307	0	0	0.292
2005	1	0	0.573	0	0	0.314
2006	0	0	0.210	0	0	0.215
Canyonlands	0					
2002	4	0	0.856	1	0	0.511
2005	5	0	0.843	0	0	0.406
2006	1	0	0.539	0	0	0.350
Bryce Canyon	0					
2002	0	0	0.186	0	0	0.111
2005	0	0	0.156	0	0	0.103
2006	0	0	0.064	0	0	0.078

max visibility impact at any receptor (24-hour average)

Visibility Impacts at Class II Areas due to the Project Alone

Table 38 lists the CALPUFF-estimated visibility impacts at the Class II areas due to the Project using the two calculation methods described above. Due to the Project alone, there are no days that exceed the 1.0 dv threshold. The 0.5 dv threshold is exceeded for four days at the High Uinta Class II area using Method 2. Using Method 6, the 0.5 dv threshold is not exceeded for any Class II area. The 0.5 dv threshold is not exceeded for any other Class II area using either method. It should be noted that Class II areas have no visibility protection under federal, tribal, state or local laws. The following information is presented for disclosure purposes only.

Table 36**.** ALPUFF-Estimated Visibility Impacts on Class II Areas for the Project Alone using Methods 2 and 6.

	Method Visibility = 2			Method Visibility = 6		
	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)
Brown Park	0					
2002	0	0	0.135	0	0	0.061
2005	0	0	0.213	0	0	0.070
2006	0	0	0.105	0	0	0.060
Colorado NM	0					
2002	0	0	0.130	0	0	0.083
2005	0	0	0.099	0	0	0.054
2006	0	0	0.160	0	0	0.112
Dinosaur NM	0					
2002	0	0	0.300	0	0	0.186
2005	0	0	0.482	0	0	0.155
2006	0	0	0.231	0	0	0.163
Flaming Gorge	0					
2002	0	0	0.232	0	0	0.091
2005	0	0	0.361	0	0	0.115
2006	0	0	0.127	0	0	0.070
Hunter Frying Pan	0					
2002	0	0	0.022	0	0	0.017
2005	0	0	0.019	0	0	0.017
2006	0	0	0.022	0	0	0.015
Holy Cross	0					
2002	0	0	0.017	0	0	0.017
2005	0	0	0.015	0	0	0.018
2006	0	0	0.024	0	0	0.023
High Uinta	0					
2002	0	0	0.448	0	0	0.245
2005	4	0	0.816	0	0	0.263
2006	0	0	0.189	0	0	0.100
Raggeds	0					
2002	0	0	0.044	0	0	0.028
2005	0	0	0.034	0	0	0.037
2006	0	0	0.046	0	0	0.023

max visibility impact at any receptor (24-hour average)

4.5.9.5 Visibility Impacts on Class II Areas due to the Cumulative Emissions plus the Project

Table 39 lists the visibility impacts on Class II areas for the cumulative emissions plus the proposed Project. The largest and most frequent potential impacts are estimated to occur at Dinosaur National Monument, but impacts exceeding the 0.5 dv and 1.0 dv thresholds are found at nearly all sites for at least one of the modeling years. The number of days exceeding 1.0 dv change at Dinosaur National Monument ranges from 56 to 128 days across the two methods for the three-year modeling period. Other sites with frequent impacts above the 1.0 dv threshold were Flaming Gorge (46 days with Method 2 and 14 with Method 6) and Brown Park (49 days with Method 2 and 27 with Method 6). Across all sites, the number of days exceeding the 1.0 dv threshold ranges from 0 for Hunter Frying Pan (Method 6) to 128 days for Dinosaur National Monument (Method 2).

Table 37**.** CALPUFF-Estimated Visibility Impacts on Class II Areas for the Cumulative Emissions plus Project using Method 2 and Method 6.

	Method Visibility = 2			Method Visibility = 6		
	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)
Brown Park						
2002	45	23	5.392	25	13	2.637
2005	48	19	3.868	31	11	2.464
2006	24	7	1.623	19	3	1.419
Colorado NM						
2002	46	7	2.723	39	8	1.570
2005	23	2	1.368	23	4	1.110
2006	17	1	1.141	21	2	1.171
Dinosaur NM						
2002	101	53	5.313	83	24	2.452
2005	99	47	4.024	68	18	2.465
2006	63	28	2.799	54	14	2.282
Flaming Gorge						
2002	42	19	4.246	26	6	2.224
2005	39	21	4.318	28	8	2.108
2006	22	6	1.636	19	0	0.875
Hunter Frying Pan						
2002	11	0	0.940	2	0	0.609
2005	4	0	0.727	0	0	0.407
2006	6	1	1.030	2	0	0.602
Holy Cross						
2002	14	1	1.281	7	1	1.002
2005	4	1	1.262	2	0	0.828
2006	6	0	0.791	2	0	0.552
High Uinta						
2002	51	22	2.830	22	2	1.081
2005	29	16	3.453	9	3	1.594
2006	9	1	1.097	2	0	0.544
Raggeds						
2002	17	2	1.411	7	0	0.712
2005	2	0	0.528	0	0	0.405
2006	8	1	1.145	1	0	0.507

max visibility impact at any receptor (24-hour average)

4.5.9.6 Visibility Impacts on Class II Areas due to the Project plus Cumulative Emissions Without RFD Sources

Table 40 lists the visibility impacts for the Project together with cumulative emissions without the RFD sources. With the RFD sources removed, visibility impacts are greatly reduced. Using Method 6, only the Dinosaur National Monument and High Uinta Class II areas have any days with impacts above the 1.0 dv threshold (10 days and 1 day respectively). Using Method 2, the number of days with impacts over 1.0 dv is 53 for Dinosaur National Monument and 25 for High Uinta WA. Other sites with the most frequent impacts were the Flaming Gorge (14 for Method 2 and 0 for Method 6) and Brown Park (11 for Method 2 and 0 for Method 6) Class II Areas.

Table 38**.** CALPUFF-Estimated Visibility Impacts on Class II Areas for the Cumulative Emissions plus the Project without RFD Sources using Method 2 and Method 6.

	Method Visibility = 2			Method Visibility = 6		
	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)	# Days ≥ 0.5 dv	# Days ≥ 1.0 dv	Max (dv)
Brown Park						
2002	20	6	1.884	3	0	0.767
2005	17	5	1.710	4	0	0.684
2006	2	0	0.662	0	0	0.389
Colorado NM						
2002	16	2	1.261	10	0	0.706
2005	4	0	0.641	4	0	0.596
2006	1	0	0.546	1	0	0.593
Dinosaur NM						
2002	61	25	2.816	40	7	1.194
2005	56	25	3.647	28	3	1.216
2006	19	3	1.762	7	0	0.774
Flaming Gorge						
2002	24	9	1.683	7	0	0.975
2005	18	5	2.274	5	0	0.725
2006	2	0	0.936	0	0	0.436
Hunter Frying Pan						
2002	0	0	0.423	0	0	0.305
2005	0	0	0.332	0	0	0.204
2006	0	0	0.279	0	0	0.214
Holy Cross						
2002	1	0	0.537	0	0	0.408
2005	1	0	0.509	0	0	0.325
2006	0	0	0.268	0	0	0.204
High Uinta						
2002	41	15	1.798	16	0	0.704
2005	24	9	3.392	6	1	1.136
2006	4	1	1.039	0	0	0.476
Raggeds						
2002	1	0	0.651	0	0	0.409
2005	0	0	0.430	0	0	0.225
2006	1	0	0.500	0	0	0.242

5.0 REFERENCES

American Petroleum Institute, 2004. "Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. Developed by URS Corporation, Amberglen, TX, for API. February.

Atkinson, D. and T. Fox. 2006. Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF. Memorandum from U.S. EPA/OAQPS to Kay T. Prince, EPA Region 4. March.

Brode, R.W., J. Wang. 1992. "User's Guide for the Industrial Source Complex (ISC2) Dispersion Models Volumes I-III." EPA-450/4-92-008a. EPA-450/4-92-008b. EPA-450/4-92-008c. U.S. Environmental Protection Agency, Research Triangle Park, North Carolina.

Bureau of Land Management, 2006. "Atlantic Rim Gas Development Project Final Environmental Impact Statement". Available at http://www.blm.gov/wy/st/en/info/NEPA/rfodocs/atlantic_rim.html.

Bureau of Land Management, 2007. "Air Quality Technical Support Document for the Moxa Arch Area Infill Gas Development Project Draft Environmental Impact Statement". Available at http://www.blm.gov/wy/st/en/info/NEPA/kfodocs/moxa_arch.html.

Bureau of Land Management, 2008a. "Proposed Oil Shale and Tar Sands Resource Management Plan Amendments to Address Land Use Allocations in Colorado, Utah, and Wyoming and Final Programmatic Environmental Impact Statement". Available online at http://ostseis.anl.gov/eis/guide/index.cfm. September, 2008.

Bureau of Land Management, 2008b. "Air Quality Technical Support Document for the West Tavaputs Plateau EIS". Draft EIS may be found online at http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/Draft_EIS.html

Buys and Associates, 2007. "Air Quality Technical Support Document for the West Tavaputs Plateau Oil and Gas Producing Region Environmental Impact Statement". Prepared for the Bureau of Land Management Price Field Office. November.

Buys and Associates, 2008. "Air Quality Technical Support Document for the Hell's Gulch and Hightower Mountain Natural Gas Development Projects and Cumulative Analysis". Revised February 2008. Prepared for the U.S. Forest Service and the Grand Mesa Uncompagre Gunnison National Forest Grand Valley Ranger District. March, 2008.

Center for Climate Strategies, 2007. "Final Utah Greenhouse Gas Inventory and Reference Case Projections, 1990-2020". Prepared for the Utah Department of Environmental Quality. February.

CDPHE. 2005. "CALMET/CALPUFF BART Protocol for Class I federal Area Individual Source Attribution Visibility Impairment Modeling Analysis." Colorado Department of Public Health and Environment, Air Pollution Control Division, Denver, Colorado. October.

Energy Information Administration, 2006. “Greenhouse Gases in the United States”. Report #: DOE/EIA-0573. Available at http://www.eia.doe.gov/oiaf/1605/archive/gg07rpt/index.html.

ENVIRON. 2007. “Air Quality Impact Protocol for the Continental Divide-Creston Project Environmental Impact Statement.” ENVIRON International Corporation, Novato, California. July.

ENVIRON. 2008. “Air Quality Impact Protocol for the Ashley National Forest South Unit Master Development Plan Environmental Impact Statement.” ENVIRON International Corporation, Novato, California. May.

EPA. 1990. “Draft New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting.” Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. October.

EPA. 1991. “Guideline for Regulatory Application of the Urban Airshed Model,” EPA-450/4-91-013, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711. July.

EPA. 2001. “Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze”, Draft Report, U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA. 2003a. “Guidance for Tracking Progress Under the Regional Haze Rule.” Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

EPA. 2003b. “Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.” Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina.

EPA. 2003c. “Revisions to the Guideline on Air Quality Models: Adoption of a Preferred Long Range Transport Model and Other Resources”; Final Rule. *Federal Register Volume*. 68, No. 72/Tuesday April 15, 2003/Rules and Regulations. 40 CFR51.

EPA, Office of Transportation and Air Quality, Assessment and Standards Division, 2004. "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling--Compression-Ignition", Report No. NR-009c, Revised April 2004, (EPA420-P-04-009).

EPA. 2005a. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule, *Federal Register Volume* 70, No. 128, July.

EPA, Office of Transportation and Air Quality, Assessment and Standards Division, 2005b. "Conversion Factors for Hydrocarbon Emission Components NR-002c", Report No. NR-002c, Revised December, 2005, (EPA420-R-05-015).

EPA. 2007a. “Guidance on the Use of Models and other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze.” Office of Air Quality Planning and Standards, Air Modeling Group. Research Triangle Park, North Carolina (http://www.epa.gov/scram001/guidance/guide/final-03-pm-rh-guidance.pdf).

EPA, 2001-2008. "AP-42: Compilation of Air Pollutant Emission Factors, Volume 1. Stationary Point and Area Sources". http://www.epa.gov/ttn/chief/ap42/index.html.

Fiore, A.M. D. J. Jacob, I. Bey, R. M. Yantosca, B.D. Field, and A. C. Fusco, 2002. Background ozone over the United States in summer: Origin, trend, and contribution to pollution episodes. J. Geophys. Res. **107,** 1029-1064,

FLAG. 2000. “Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report.” U.S. Forest Service-Air Quality Program, National Park Service-Air Resources Division, U.S. Fish and Wildlife Service-Air Quality Branch. December.

Fox, Douglas, Ann M. Bartuska, James G. Byrne, Ellis Cowling, Rich Fisher, Gene E. Likens, Steven E. Lindberg, Rick A. Linthurst, Jay Messer, and Dale S. Nichols. 1989. “A Screening Procedure to Evaluate Air Pollution Effects on Class I Wilderness Areas.” General Technical Report RM-168. U.S.D.A. Forest Service, Rocky Mountain Forest and Range Experiment Station, Fort Collins, Colorado. 36 pp.

Friesen, R., R. Parikh, J. Grant, A. Bar-Ilan, A. Pollack, D. Henderer, D. Pring, K. Sgamma, and P. Schlagel, 2008. "Development of Baseline 2006 Emissions From Oil and Gas Activity in the Uinta Basin". Prepared for the Independent Petroleum Producers of the Mountain States. July.

Intergovernmental Panel of Climate Change (IPCC), World Meteorological Office, United Nations Environmental Programme, 1995. "Radiative Forcing of Climate Change. The 1994 Report of the Scientific Assessment Working Group of IPCC. Summary for Policymakers". Available online at http://www.ipcc.ch/index.htm.

IWAQM. 1998. “Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts.” EPA-454/R-98-019. Office of Quality Planning and Standards. U.S. EPA, Research Triangle Park, North Carolina. December.

Kemball-Cook, S., Y. Jia, C. Emery, R. Morris, Z. Wang and G. Tonnesen. 2004. “2002 Annual MM5 Simulation to Support WRAP CMAQ Visibility Modeling for the Section 308 SIP/TIP – MM5 Sensitivity Simulations to Identify a More Optimal MM5 Configuration for Simulating Meteorology in the Western United States.” Western Regional Air Partnership, Regional Modeling Center. December. (http://pah.cert.ucr.edu/aqm/308/reports/mm5/MM5SensitivityRevRep_Dec_10_2004.pdf).

Malm, W., M. Pitchford, M. Scruggs, J. Sisler, R. Ames, S. Copeland, K. Gebhart and D. Day. 2000. “Spatial and Seasonal Patterns and Temporal Variability of Haze and its Constituents in the United States.” Cooperative Institute for Research in the Atmosphere, Colorado State University, Fort Collins, CO. May.

Morris, R., B. Wang, E. Tai, D. McNally, C. Loomis, G. Stella and T.W. Tesche. 2007. “Modeling Protocol for the Denver 8-Hour Ozone Attainment Demonstration Modeling. Prepared for Denver Regional Air Quality Council.” Prepared by ENVIRON International Corporation, Novato, California. November. (http://www.ozoneaware.org/documents/DraftFinalProtocolDenver8-HourOzoneNov282007.pdf)

Natural Resource Group, Inc. 2006a. Air Quality Impact Assessment Protocol, Moxa Arch Infill Drilling Project, Lincoln, Unita, and Sweetwater Counties, Wyoming. Natural Resource Group, Inc., Denver, Colorado. December.

Natural Resource Group, Inc. 2006b. Air Quality Impact Assessment Protocol, Hiawatha Regional Energy Development Project, Sweetwater County, Wyoming and Moffat County, Colorado. Natural Resource Group, Inc., Denver, Colorado. November.

Pollack, A., J. Russell, J. Grant, R. Friesen, P. Fields, and M. Wolfe, 2006: Ozone Precursor Emission Inventory for the San Juan and Rio Arriba Counties, New Mexico. Report prepared for the New Mexico Environment Department. Available online at http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/NM_Area_Emissions_report.pdf.

Sage Consulting and ENVIRON, 2007. Draft Air Quality Impact Assessment Protocol for the Continental Divide-Creston Project Environmental Impact Statement. Prepared for the Bureau of Land Management Rawlins Field Office and Wyoming State Office. July.

Scire, J.S., D.G. Strimaitis, R.J. Yamartino. 2000a. “A User's Guide for the CALPUFF Dispersion Model.” Earth Tech, Concord, MA, January.

Scire, J.S., F. Robe, F.E. Fernau, R.J. Yamartino. 2000b. “A User's Guide for the CALMET Meteorological Model.” Earth Tech, Concord, MA, January.

U.S.D.A. Forest Service. 2000. “Screening Methodology for Calculating ANC Change to High Elevation Lakes.” User's Guide. U.S. Department of Agriculture (USDA) Forest Service, Rocky Mountain Region. January.

Wyoming Department of Environmental Quality Air Quality Division, 2007. "Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance", August, 2007. Available online at http://deq.state.wy.us/AQD/Oil%20and%20Gas/AUGUST%202007%20O&G%20GUIDANCE%20-%20FINAL.pdf.

APPENDIX A
Project Emissions Inventory

Table A1: Project Emission Assumptions

Ashley National Forest /South Unit EIS Project Emission Inventory
July, 2008

This spreadsheet contains estimates for emissions for the Ashley National Forest/South Unit Project proposed by Berry Petroleum (the Operators). Operators plan 400 new oil/gas wells over 20 years to be drilled ~10 miles south of Duchesne, UT. Worksheets with yellow tabs contain project information supplied by the Operators.

Well Emission Assumptions
Operators do not expect to do any venting of the wells
Operators do not expect to do any flaring or blowdowns
Assume fuel is low sulfur diesel
No pumps, injection devices, or pneumatic devices at the well site
No well head compression. All compression will be handled at 4 new central compression/gas processing facilities.
No heaters on produced water tanks, no combustion units on oil tanks
Only equipment at site is well, pumpjack, two oil tanks, each with a heater
Operators expect no venting of gas during completion
Assuming all 400 wells are productive, Operators anticipate production of 4000 bbl/day oil and 20 MMscf/day gas
and 50 bbl condensate/day
No separators at well site-water and oil separate within the tanks.
Crude oil to be hauled away by truck every 8 days
Natural gas to be dehydrated and compressed at up to 4 new compressor stations within or adjacent to the Project area.
Gas Composition Analysis, compressor station emissions, and truck traffic analysis provided by Operators
Per Park Service guidance for PM speciation, and following Hell's Gulch/Hightower EA, as directed by stakeholders,
speciate PM from combustion sources such that 37% of particles are assumed to be filterable and 63% assumed to
be condensable. Filterable particles are assigned to EC, condensables to SOA
Assume N2O emissions negligible compared to CO2 for combustion sources (API, 2004)
Assume drilling proceeds at an even pace of 20 wells per year for 20 years

Table A2: References

References

American Petroleum Institute, 2004. "Comprendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. Developed by URS Corporation, Amberglen, TX, for API. February.

BLM, 2008. "Air Quality Technical Support Document for the West Tavaputs Plateau EIS". Draft EIS may be found at http://www.blm.gov/ut/st/en/fo/price/energy/Oil_Gas/Draft_EIS.html

BLM, 2008. "Air Quality Impact Assessment Technical Support Document, Little Snake Resource Management Plan, Moffat, Routt and Rio Blanco Counties, Colorado." Not yet released.

Buys and Associates, 2008. Air Quality Technical Support Document for the Hell's Gulch and Hightower Mountain Natural Gas Development Projects and Cumulative Analysis. Prepared for the U.S. Forest Service, White River National Forest, Rifle Ranger District, Grand Mesa Uncompahgre Gunnison National Forest, and the Grand Valley Ranger District.

Energy Information Administration, 2006. "Greenhouse Gases in the United States". Report #: DOE/EIA-0573. Available at http://www.eia.doe.gov/oiaf/1605/archive/gg07rpt/index.html.

Center for Climate Strategies, 2007. "Final Utah Greenhouse Gas Inventory and Reference Case Projections, 1990-2020". Prepared for the Utah Department of Environmental Quality. February, 2007.

EPA, Office of Transportation and Air Quality, Assessment and Standards Division, 2004. "Exhaust and Crankcase Emission Factors for Nonroad Engine Modeling--Compression-Ignition", Report No. NR-009c, Revised April 2004, (EPA420-P-04-009)

EPA, Office of Transportation and Air Quality, Assessment and Standards Division, 2005. "Conversion Factors for Hydrocarbon Emission Components NR-002c", Report No. NR-002c, Revised December, 2005, (EPA420-R-05-015)

EPA, 2001-2008. "AP-42: Compilation of Air Pollutant Emission Factors, Volume 1. Stationary Point and Area Sources". http://www.epa.gov/ttn/chief/ap42/index.html

Friesen, R., R. Parikh, J. Grant, A. Bar-Ilan, A. Pollack, D. Henderer, D. Pring, and M. Young, 2008. "Development of Baseline 2006 Emissions From Oil and Gas Activity in the Uinta Basin". Prepared for the Independent Petroleum Producers of the Mountain States.

Intergovernmental Panel of Climate Change (IPCC), 1995. World Meteorological Office, United Nations Environmental Programme, "Radiative Forcing of Climate Change. The 1994 Report of the Scientific Assessment Working Group of IPCC. Summary for Policymakers".

Pollack, A., J. Russell, J. Grant, R. Friesen, P. Fields, and M. Wolfe, 2006: Ozone Precursor Emission Inventory for the San Juan and Rio Arriba Counties, New Mexico. Report prepared for the New Mexico Environment Department. http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/NM_Area_Emissions_report.pdf

Wyoming Department of Environmental Quality Air Quality Division, 2007. "Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance", August, 2007. http://deq.state.wy.us/AQD/Oil%20and%20Gas/AUGUST%202007%20O&G%20GUIDANCE%20-%20FINAL.pdf

Table A3: Gas Composition Analysis

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A		Descriptior	Brundage Plant Inlet
Analysis Date/Time:	11/8/2006	11:17 AM	Field:	Brundage
Analyst Initials:	AST		ML#:	Berry Petroleum
Instrument ID:	Instrument 1		GC Methoc	Quesbtex
Data File:	QPC16.D			
Date Sampled:	11/6/2006			

Component	Mol%	Wt%	LV%	Wt%
Methane	86.9887	72.6387	80.5346	72.6387
Ethane	6.3899	10.0011	9.3592	10.0011
Propane	3.3484	7.6855	5.0425	7.6855
Isobutane	0.5345	1.6171	0.9556	1.6171
n-Butane	0.9979	3.0189	1.7194	3.0189
Neopentane	0.0041	0.0154	0.0086	0.0154
Isopentane	0.2501	0.9392	0.5003	0.9392
n-Pentane	0.2856	1.0724	0.5653	1.0724
2,2-Dimethylbutane	0.0020	0.0088	0.0045	0.0088
2,3-Dimethylbutane	0.0185	0.0828	0.0414	0.0828
2-Methylpentane	0.0510	0.2286	0.1156	0.2286
3-Methylpentane	0.0216	0.0968	0.0481	0.0968
n-Hexane	0.0693	0.3107	0.1556	0.3107
Heptanes	0.0800	0.3854	0.1722	0.3854
Octanes	0.0072	0.0430	0.0197	0.043
Nonanes	0.0017	0.0102	0.0044	0.0102
Decanes plus	0.0002	0.0013	0.0006	0.0013
Nitrogen	0.3970	0.5789	0.2379	0.5789
Carbon Dioxide	0.5523	1.2652	0.5145	1.2652
Oxygen	0.0000	0.0000	0.0000	0
Hydrogen Sulfide	0.0000	0.0000	0.0000	0
Total	100.0000	100.0000	100.0000	100

Global Properties		Units
Gross BTU/Real CF	1165.8	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1146.8	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6649	air=1
Avg Molecular Weight	19.212	gm/mole
Propane GPM	0.920573	gal/MCF
Butane GPM	0.488360	gal/MCF
Gasoline GPM	0.293369	gal/MCF
26# Gasoline GPM	0.607385	gal/MCF
Total GPM	1.702414	gal/MCF
Base Mol%	99.820	%v/v
Sample Temperature:	55	°F
Sample Pressure:	870	psig

Reviewed By: ______________________________

Component	Mol%	Wt%	LV%
Benzene	0.0042	0.0171	0.0064
Toluene	0.0020	0.0096	0.0037
Ethylbenzene	0.0001	0.0005	0.0002
M&P Xylene	0.0003	0.0018	0.0007
O-Xylene	0.0001	0.0004	0.0001
2,2,4-Trimethylpentane	0.0034	0.0205	0.0094
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0150	0.0657	0.0279
Methylcyclohexane	0.0096	0.0489	0.0210
Description:	Brundage Plant Inlet		

Table A4: GlyCALC Analysis

GRI GlyCalc Information

Component	Mol%	Wt%	LV%	Wt%
Carbon Dioxide	0.5523	1.2652	0.5145	1.2652
Hydrogen Sulfide	0.0000	0.0000	0.0000	0
Nitrogen	0.3970	0.5789	0.2379	0.5789
Methane	86.9887	72.6387	80.5346	72.6387
Ethane	6.3899	10.0011	9.3592	10.0011
Propane	3.3484	7.6855	5.0425	7.6855
Isobutane	0.5345	1.6171	0.9556	1.6171
n-Butane	0.9979	3.0189	1.7194	3.0189
Isopentane	0.2542	0.9546	0.5089	0.9546
n-Pentane	0.2856	1.0724	0.5653	1.0724
Cyclopentane	0.0000	0.0000	0.0000	0.0000
n-Hexane	0.0693	0.3107	0.1556	0.3107
Cyclohexane	0.0150	0.0657	0.0279	0.0657
Other Hexanes	0.0931	0.4170	0.2096	0.4170
Heptanes	0.0458	0.2236	0.1038	0.2236
Methylcyclohexane	0.0096	0.0489	0.0210	0.0489
2,2,4 Trimethylpentane	0.0034	0.0205	0.0094	0.0205
Benzene	0.0042	0.0171	0.0064	0.0171
Toluene	0.0020	0.0096	0.0037	0.0096
Ethylbenzene	0.0001	0.0005	0.0002	0.0005
Xylenes	0.0004	0.0022	0.0008	0.0022
C8+ Heavies	0.0086	0.0518	0.0237	0.0518
Subtotal	100.0000	100.0000	100.0000	100.0000
Oxygen	0.0000	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000	100.0000
			VOC weight %	15.52
			VOC weight fraction	0.155161
			THC weight %	98.1559

Table A4: Truck Traffic Estimates

Ashley NF South Unit EIS Project
Berry Petroleum Company
Truck Traffic Estimate - Per Well
March 1, 2008

Truck traffic estimates provided by Operators

I. Road and Pad Construction		Light Trucks	Heavy Trucks	Activity
8 x 12-hour days	Day 1	1	1	Deliver dozer, start road construction
	Day 2	1	0	Crew commutes to site, construction activity
	Day 3	1	1	Crew commutes to site, construction activity, fuel delivery
	Day 4	1	0	Complete construction of road, move dozer to pad
	Day 5	1	0	Start pad construction
	Day 6	1	1	Crew commutes to site, pad construction activity, fuel delivery
	Day 7	1	0	Crew commutes to site, pad construction activity
	Day 8	1	1	Complete pad construction, demob dozer, leave site
	Total	8	4	
	Avg/Day	1	0.5	

II. Well Drilling		Light Trucks	Heavy Trucks	Activity
7 x 24-hour days	Day 1	14	30	Deliver rig, rig set up
	Day 2	10	4	Drill well
	Day 3	14	16	Drill well, set surface casing
	Day 4	10	4	Drill well
	Day 5	10	4	Drill well
	Day 6	10	4	Drill well
	Day 7	20	30	Run and cement production casing, demob rig
	Total	88	92	
	Avg/Day	12.6	13.1	

III. Well Completion		Light Trucks	Heavy Trucks	Activity
14 x 12 hour days	Day 1	3	5	Deliver completion rig, frac tanks, and related equipment
	Day 2	3	7	Deliver water, rig set up
	Day 3	3	7	Deliver water, tubing
	Day 4	3	7	Deliver water, tubing
	Day 5	6	10	Perf and frac well
	Day 6	6	10	Perf and frac well
	Day 7	6	10	Perf and frac well
	Day 8	3	0	Flow well, vent gas
	Day 9	3	0	Flow well, vent gas
	Day 10	3	0	Flow well, vent gas
	Day 11	3	7	Demob rig, remove tanks and equipment
	Day 12	3	7	Demob rig, remove tanks and equipment
	Day 13	3	3	Site clean up
	Day 14	3	3	Site clean up
	Total	51	76	
	Avg/Day	3.6	5.4	

IV. Production Equipment Install		Light Trucks	Heavy Trucks	Activity
7 x 12-hour days	Day 1	2	2	Deliver and set crude oil tanks
	Day 2	2	2	Deliver pumpjack components, production piping, hardware
	Day 3	2	2	Deliver pumpjack components, production piping, hardware
	Day 4	2	2	Equipment installation
	Day 5	2	2	Equipment installation, testing
	Day 6	2	2	Equipment start up
	Day 7	2	2	Commence production, site clean up
	Total	14	14	
	Avg/Day	2.0	2.0	

V. Production Phase (per well)		Light Trucks	Heavy Trucks	Activity
20 years	Each Day	1	0.125	One crude oil load out each 8 days

Table A5: Compressor Engine Information

Compressor station information provided by the Operators

				NOx		CO		VOC		Formaldehyde		
Engine Description	Design Heat Input Rate (MMBtu/hr)[1]	Maximum Site Loading (hp)	Hours of Operation (hrs/yr)	Emission Factor (g/hp-hr)[2]	Emissions (ton/yr.)	Emission Factor (g/hp-hr)[2]	Emissions (ton/yr.)	Emission Factor (g/hp-hr)[2]	Emissions (ton/yr.)	Emission Factor (lb/MMBtu)[3]	Emission Factor (g/hp-hr)[2]	Emissions (tons/yr.)
Section 21 - Cat 3512LE	7.44	1005	8760	2.0	19.41	1.6	15.53	0.5	4.56	0.05		1.72
Section 7 - Cat 3512LE	7.44	1005	8760	2.0	19.41	1.6	15.53	0.5	4.56	0.05		1.72
Section 7 - Wauk L36GL		800	8760	1.0	7.73	1.3	10.04	0.4	3.09		0.19	1.47
TOTAL					27.13		25.57		7.65			3.19
Section 23 - Cat 3516LE		1200	8760	1.5	17.38	1.9	22.13	0.5	5.79		0.26	3.01
Section 23 - Cat 3516LE		1200	8760	1.5	17.38	1.9	22.13	0.5	5.79		0.26	3.01
TOTAL					34.76		44.26		11.59			6.03
Section 22 - Cat 3516LE		1200	8760	1.5	17.38	1.9	22.13	0.5	5.79		0.26	3.01
Section 22 - Cat 3512LE	5.48	740	8760	2.0	14.29	1.6	11.43	0.5	3.57	0.05		1.27
TOTAL					31.67		33.57		9.37			4.28

Equations

(1) Design Heat Input = brake-specific fuel consumption (BSFC) Btu/hp-hr X Maximum Site Loading (hp)

(2) Manufacturer Emission Rates

$$\text{Emissions (lb/hr)} = \frac{\text{Emission Factor (g/hp-hr)} \times \text{Maximum Site Loading (hp)}}{\text{453.59 (g/lb)}}$$

$$\text{Annual Emissions (to} \; \frac{\text{Emissions (lb/hr)} \times \text{Hours of Operation (hrs/yr.)}}{\text{2000 lbs./ton}}$$

(3) AP-42 Table 3.2-2 Uncontrolled Emission Factors for a 4 stroke Lean Burn engine (7/00).

Emissions (lb/hr) = Emission factor (lb/MMBtu) X Design Heat Input Rate (MMBtu/hr)

$$\text{Annual Emissions (to} \; \frac{\text{Emissions (lb/hr)} \times \text{Hours of Operation (hrs/yr.)}}{\text{2000 lbs./ton}}$$

Table A7: Wind Speed Data for Grand Junction, CO

Grand Junction, CO (1947-1979) http://www.itl.nist.gov/div898/winds/nondirectional.htm
Data from NIST Extreme Wind Speed Data Sets: Non-Directional Wind Speeds

Year		Fastest Mile (mph)	3-s peak gusts (mph)	3-s peak gusts (m/s)	Average of Annual Fastest Mile =	
1947	S	61	74	33		52.12 mph
1948	S	52	64	29		23.30 m/s
1949	NW	56	69	31		
1950	S	52	64	29		
1951	S	60	73	33		
1952	S	55	68	30		
1953	SW	56	69	31		
1954	S	59	72	32		
1955	W	54	66	30		
1956	SW	51	63	28		
1957	W	51	63	28		
1958	SW	51	63	28		
1959	NW	45	57	25		
1960	S	51	63	28		
1961	NW	45	57	25		
1962	NW	52	64	29		
1963	N	47	59	26		
1964	W	53	66	30		
1965	NE	53	66	30		
1966	NW	70	84	38		
1967	W	60	73	33		
1968	NE	45	57	25		
1969	NW	52	64	29		
1970	SW	54	66	30		
1971	W	46	58	26		
1972	SW	48	60	27		
1973	NW	51	63	28		
1974	SW	48	60	27		
1975	SW	51	63	28		
1976	S	53	66	30		
1977	S	51	63	28		
1978	SW	43	54	24		
1979	W	44	55	25		

Table A8: Well Pad Construction Assumptions

Assumptions:

Emission factors from (EPA, 2004; EPA420-P-04-009) p. A-7

Crankcase Emission factors are 2% of HC Exhaust Emission Factor for Tier II and earlier per

EPA NONROAD Modeling Guidance p. 23 (EPA, 2004; EPA420-P-04-009).

VOC/THC= 1.053 Conversion for HC->VOC for diesel engines (EPA, 2005; EPA420-R-05-0159, p. 5)

Loads based on Appendix B of the Jonah EIS Table B.1.4-Taken from "Surface Mining" (Pfleider 1972) for average service duty.

The overall load factor is 0.4 for motor grader and D8 Dozer for Jonah EIS

Load factor is 0.4 for well pad heavy construction equipment for West Tavaputs EIS (2007)

HP not available from operators, so estimated HP from comparable models

Since engine tiers are unknown (see operator information below), assumed Tier 0

Per USPS Guidance, 37% of fine particles assumed to be filterable and all filterable are assigned to EC

Per USPS Guidance, 63% of fine particles assumed to be filterable and all filterable are assigned toSOA

Information from operators :

Total time to build the well pad is 8 days

For pad construction, we use 2 Cat D-8R Dozers, 2001, 2004; and one Champion 738 (14 ft. blade) Grader, 1999.

Hours of use = 70 per well pad. Tiers and emission factors unknown.

Equations:

$$\text{Emissions (tons/year-well)} = \frac{\text{Emission factor (g/hp-hr)} * \text{Horsepower} * \text{Time Used (hours)} * \text{Load}}{453.5\ \text{(g/lb)} * 2000\ \text{(lbs/ton)}}$$

Deterioration Calculation Method from EPA (2004) p. 19

DF = deterioration factor=$1+A^B$

A = Relative Deterioration Factor (% increase/%useful life)

B = 1 for diesel nonroad engines

Emission factor = (Steady-state, zero hour emission factor) x (Deterioration Factor)

Assume engines are completely deteriorated

Table A9: Well Pad Construction Emissions

Well Pad Construction Emissions Per Well

Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
tons/well	0.2079	0.00012	0.0775	0.0185	0.0113	0.0109	0.0040	0.0069	12.8138
lbs/hr	5.9402	0.0034	2.2148	0.5293	0.3222	0.3125	0.1156	0.1969	366.1076

Well Pad Construction Equipment Exhaust Emissions Per Well (lbs/hr)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
CAT D-8 Dozer	4.7	0.0	1.7	0.4	0.3	0.2	0.1	0.2	289.2
Champion 738 Grader	1.2	0.0	0.5	0.1	0.1	0.1	0.024	0.041	77.0
Total	5.9	0.00	2.2	0.5	0.3	0.3	0.1	0.2	366.1

Well Pad Construction Equipment Exhaust Emissions Per Well (lbs/year-well)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
CAT D-8 Dozer	328.4	0.19	122.5	29.3	17.8	17.3	6.4	10.9	20240.9
Champion 738 Grader	87.4	0.05	32.6	7.8	4.7	4.6	1.7	2.9	5386.7
Total	415.8	0.24	155.0	37.1	22.6	21.9	8.1	13.8	25627.5

Well Pad Construction Equipment Utilization

Equipment Type	# Units	Tier Level	Model Year	Time Used Per Unit (hours)	HP	Load (%)	BSFC (lb/hp-hr)
CAT D-8 Dozer	2	0	2001, 2004	70	310	0.4	0.367
Champion 738 Grader	1	0	1999	70	165	0.4	0.367

Well Pad Construction Equipment Exhaust Steady-State, Zero Hour Emission Factors

Equipment Type	NOx (g/hp-hr)	SO_2 (g/hp-hr)	CO (g/hp-hr)	HC (g/hp-hr)	VOC (g/hp-hr)	PM10 (g/hp-hr)	PM2.5 (g/hp-hr)	CO_2 (g/hp-hr)
CAT D-8 Dozer	8.4	0.0049	2.7	0.68	0.71604	0.315985	0.306505	528.8739
Champion 738 Grader	8.4	0.0049	2.7	0.68	0.71604	0.315985	0.306505	528.8739

NOx, CO, HC, PM Emission factors from EPA (2004) Table A-2, Zero Hour Steady State Emission Factors for Nonroad CI Engines.
SO_2 emission factor calculated from EPA (2004) Equation 7. See below for description of method.

Crankcase Emission Factors (g/hp-hour)

Equipment Type	HC Tier 0	VOC Tier 0
CAT D-8 Dozer	0.0136	0.0143
Champion 738 Grader	0.0136	0.0143

Tier 0 Deterioration Factors from EPA (2004) NONROAD Table A4

	DF	A
HC	1.047	0.047
CO	1.185	0.185
NOx	1.024	0.024
PM	1.473	0.473

1 **Table A10: Well Pad Construction Emissions, continued.**

EPA NONROAD Model SO2 Emission Factor methodology (EPA, 2004; p. 22)

The model does not require an SO_2 emission factors input like other. EPA will calculate SO_2 emission factors as shown in the equation below.

$$SO_2 = (BSFC * 453.6 * (1 - soxcnv) - HC) * 0.01 * soxdsl * 2 \quad \text{[Equation 7]}$$

where

SO_2 is in g/hp-hr
BSFC is the in-use adjusted fuel consumption in lb/hp-hr
453.6 is the conversion factor from pounds to grams
soxcnv is the fraction of fuel sulfur converted to direct PM
HC is the in-use adjusted hydrocarbon emissions in g/hp-hr
0.01 is the conversion factor from weight percent to weight fraction
soxdsl is the episodic weight percent of sulfur in nonroad diesel fuel
2 is the grams of SO_2 formed from a gram of sulfur

Sulfur Adjustment for PM Emissions (S_{PMadj})

Since PM emissions are dependent on the sulfur content of the fuel, an adjustment (S_{PMadj}) is subtracted from the PM emission factor to account for variations in fuel sulfur content (see equation 2 above). S_{PMadj} corrects PM emissions from the default fuel sulfur level to the episodic fuel sulfur level and is calculated using the following equation:

$$S_{PMadj} = BSFC * 453.6 * 7.0 * soxcnv * 0.01 * (soxbas - soxdsl) \quad \text{[Equation 4]}$$

where: S_{PMadj} = PM sulfur adjustment (g/hp-hr)
BSFC = in-use adjusted brake-specific fuel consumption (lb fuel/hp-hr)
453.6 = conversion from lb to grams
7.0 = grams PM sulfate/grams PM sulfur
soxcnv = grams PM sulfur/grams fuel sulfur consumed
0.01 = conversion from percent to fraction
soxbas = default certification fuel sulfur weight percent
soxdsl = episodic fuel sulfur weight percent (specified by user)

The soxcnv term represents the fraction of diesel fuel sulfur converted to PM. This varies by technology type. Soxcnv is equal to 0.02247 for the Base, T0, T1, T2, T3, T3B, T4A, and T4N technology types. For Tier 4 engines meeting stringent PM standards below 0.1 g/hp-hr, soxcnv is equal to 0.30. This applies to the T4 and T4N technology types. If the soxcnv value for a technology type is not provided in the opt file, the default value used in the model is 0.02247. Derivation of the soxcnv term is described in Appendix C.

SO2 Emission Factor Calculation Information			
Fuel sulfur content (ppm)		15	specified by Berry operators
soxdsl		0.0015	sulfur fuel weight percent
soxcnv	Tiers I-III	0.02247	grams PM sulfur/grams fuel sulfur consumed
soxcnv	Tier IV	0.3	
grams PM sulfate/grams PM sulfur		7	
soxbas		0.33	NONROAD default certification sulfur fuel weight percent (3300 ppm)

EPA NONROAD Model CO2 Emission Factor methodology (EPA, 2004; p. 22)

The NONROAD model uses in-use adjusted BSFC to compute CO_2 emissions directly, as shown in the equation below. The carbon that goes to exhaust HC emissions is subtracted as the correction for unburned fuel. This does not require a CO_2 emission factors input file.

$$CO_2 = (BSFC * 453.6 - HC) * 0.87 * (44/12) \quad \text{[Equation 6]}$$

where

CO_2 is in g/hp-hr
BSFC is the in-use adjusted fuel consumption in lb/hp-hr
453.6 is the conversion factor from pounds to grams
HC is the in-use adjusted hydrocarbon emissions in g/hp-hr
0.87 is the carbon mass fraction of diesel
44/12 is the ratio of CO_2 mass to carbon mass

2

Table A11: Pipeline Construction Assumptions

Assumptions:
No Tier information available so assumed Tier 0
Crankcase Emission factors are 2% of HC Exhaust Emission Factor for Tier II and earlier per
EPA NONROAD Modeling Guidance p. 23 (EPA, 2004; EPA420-P-04-009).
Emission factors from (EPA, 2004; EPA420-P-04-009) p. A-7
VOC/THC= 1.053 Conversion for HC->VOC for diesel engines (EPA, 2005; EPA420-R-05-0159, p. 5)
Assume engines are fully deteriorated
Assume it takes 3hrs to construct 0.25 mile of pipeline
Assumed 80 HP and 75% load for backhoe based on Moxa Arch AQTSD (BLM, 2007)

Information from Operators:
Pipelines consist of poly plastic pipe that is dragged adjacent to roads and pushed into place off the side of the road using a Case 380 backhoe.
For entire project, 130 miles of gas gathering pipeline to be installed, per Ashley NF Master development plan
Pipeline per well = 0.325 miles

Equations:

$$\text{Emissions (tons/year-well)} = \frac{\text{Emission factor (g/hp-hr)} * \text{Horsepower} * \text{Time Used (hours)} * \text{Load}}{453.5\ \text{(g/lb)} * 2000\ \text{(lbs/ton)}}$$

Deterioration Calculation Method from EPA (2004) p. 19
DF =deterioration factor=$1+A^B$
A=Relative Deterioration Factor (% increase/%useful life)
B = 1 for diesel nonroad engines
Emission factor = (Steady-state, zero hour emission factor) x (Deterioration Factor)
Assume engines are completely deteriorated

Table A12: Pipeline Construction Emissions

Pipeline Contruction Emissions Per Well

Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
tons/well	1.82E-03	1.39E-06	1.07E-03	2.82E-04	2.38E-04	2.31E-04	8.54E-05	1.45E-04	1.51E-01
lbs/hr	0.93	0.00	0.55	0.14	0.12	0.12	0.04	0.07	77.67

Pipeline Construction Emissions (lb/well)

NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
3.64	0.00	2.13	0.56	0.48	0.46	0.170825893	0.290866	302.93

Pipeline Construction Emissions (lb/hr)

NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
0.93	0.00	0.55	0.14	0.12	0.12	0.04	0.07	77.67

Equipment Utilization

Equipment Type	Qty	HP	Tier	Load	BSFC (lb/hp-hr)	Time (hr)
Case 380 Backhoe	1	80	0	0.75	0.408	3.9

Exhaust Emissions Factor (g/hp-hr) for Tier 0

Equipment Type	NOx	SO2	CO	HC	VOC	PM10	PM2.5	CO2
Case 380 Backhoe	6.90	0.01	3.49	0.99	1.04	0.626375386	0.61	587.21

Tier I Crankcase Emission Factors (g/hp-hour)

Equipment Type	HC	VOC
Case 380 Backhoe	0.0198	0.0208

SO2 Emission Factor Calculation Information			
Fuel sulfur content (ppm)		15	specified by Berry operators
soxdsl		0.0015	sulfur fuel weight percent
soxcnv	Tiers I-III	0.02247	grams PM sulfur/grams fuel sulfur consumed
soxcnv	Tier IV	0.3	
grams PM sulfate/grams PM sulfur		7	
soxbas		0.33	NONROAD default certification sulfur fuel weight percent (3300 ppm)

Tier 0 Deterioration Factors from EPA (2004) NONROAD Table A4

Pollutant	DF	A
HC	1.047	0.047
CO	1.185	0.185
NOx	1.024	0.024
PM	1.473	0.473

EPA NONROAD Model CO2 Emission Factor methodology (EPA, 2004; p. 22)

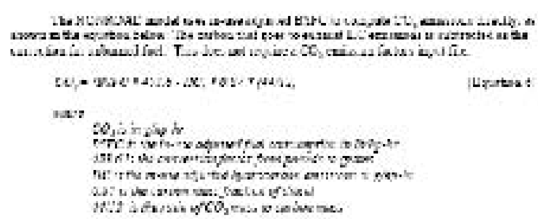


Table A13: Road and Well Pad Construction Traffic Assumptions

Assumptions

BLM, 2003 after (EPA, *AP-42* , Volume I, Section 13.2.2 Unpaved Roads (9/98))
Heavy truck weighs 70000 pounds. Average of haul, logging and mud/water truck weights from West Tavaputs EIS
Light truck weighs 8000 lbs, per West Tavaputs EIS
AP-42 Table 11.9-3 as in Jonah EIS Table B.1.3
EPA, *Control of Open Fugitive Dust Sources* , Section 5.3.1 Watering of Unpaved Surfaces (1988)

Data for Number of Days of Measurable (>0.01") Precipitation
Data assumed representative of project area from Western Regional Climate Center
for Duchesne, UT (data source nearest project area). Mean for data from 1928-2007 is
Measurable precip (>0.01") occurred on 62 days/year
http://www.wrcc.dri.edu/htmlfiles/ut/ut.01.html

Information from operators
Project area lies approximately 10 miles south of Duchesne, UT
Operators supplied truck traffic estimates-see Truck Traffic worksheet

Equations

$$\text{Emissions (tons/year-well)} = \frac{\text{Emission factor (g/mile)} * \text{\# Trips} * \text{Trip Distance (miles)}}{453.5\ \text{(g/lb)} * 2000\ \text{(lbs/ton)}}$$

$$\text{Emissions [lb/VMT]} = k\frac{(s/12)^a(W/3}{(M/0.2)^c} \; \frac{*(365-P)}{P} \; *\text{(Control Efficiency)}$$

$$SO_2 \text{ Emission Factor (g/mile)} = \frac{\text{Fuel Density (lbs/gallon)} * \text{(453.6 g/lb)} * \text{Fuel Sulfur Content} * 2}{\text{Vehicle Fuel Efficiency (miles/gallon)}}$$

Diesel fuel sulfur content assumed to be 0.05% per operators
Diesel fuel density assumed to be 7.08 lbs/gallon (As in West Tavaputs EIS)
Heavy truck fuel efficiency = 10 miles/gallon (As in West Tavaputs EIS)
Light truck fuel efficiency = 15 miles/gallon (As in West Tavaputs EIS)
Factor of 2 is the weight ratio of SO_2 to sulfur

Table A14: Road and Well Pad Construction Road Traffic Emissions

Road and Well Pad Construction Road Traffic Emissions per Well								
Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
tons/well	0.0007	0.0001	0.0033	0.0006	0.0433	0.0045	6.4E-05	1.1E-04
lbs/hr	0.00016	0.00002	0.00075	0.00013	0.00988	0.00102	0.00001	0.00002

Road and Well Pad Construction Traffic Exhaust Emissions (tons/year-well)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
Light Truck	0.0001	0.00004	0.00179	0.00011	0.00002	0.00001	4.9E-06	8.4E-06
Heavy Truck	0.0006	0.00003	0.00150	0.00045	0.00017	0.00016	5.9E-05	1.0E-04
Total	0.0007	0.0001	0.0033	0.0006	0.0002	0.0002	6.4E-05	1.1E-04

Equipment Utilization

Equipment Type	Round Trip Off-Road Trip Distance (miles)	Number of Round Trips Per Well
Light Truck	20	8
Heavy Truck	20	4
Total	40	12

Emission Factors for Exhaust from Road Traffic

Vehicle Type	Emission Factors (g/mi)							
	Class	Model Year	NO_x	PM_{10} [b,c]	$PM_{2.5}$ [b,c]	SO_x [a]	CO	VOC
Light-Duty Gasoline Truck	LDGT2	1999+	0.79	0.10	0.08	0.21	10.15	0.63
Heavy-Duty Diesel Truck	HDDV	2001+	6.49	1.96	1.81	0.32	17.06	5.08

NOx, VOC, and CO EF Source: EPA, *AP-42* , Volume II, Appendix H-117, Table 3.1A.2 Light Duty Gasoline Powered Trucks II and Appendix H-259, Table 7.1.2 Heavy Duty Diesel Powered Vehicles (High Altitude; 50,000 mileage) (6/30/95).

[a] Method from MOBILE6.1 Particulate Emission Factor Model Technical Description EPA420-R-02-012 March 2002, equation 3.7

[b] Including tire and brake wear emissions.

[c] From Moxa Arch TSD, taken from BLM, 2003, APP_A21, table 1.1.2.2, estimated using EPA PART5 Model (1995)

Fugitive Particulate Emissions Associated with Construction Traffic To Well

Source for Data for Constants: EPA (1995), AP-42, Section 13.2.2 Unpaved Roads (9/98). Table 13.2.2-2.

$$E\ [lb/VMT] = \frac{k(s/12)^a (W/3)^d}{(M/0.2)^c} \ast \frac{(365-P)}{365} \ast (\text{Control Efficiency})$$

Constant	PM_{10}	$PM_{2.5}$
k	1.8	0.18
a	1.00	1.00
d	0.50	0.50
c	0.2	0.2

Variable Description	Value	Reference
E = size-specific emission factor (lb/VMT)		
s = surface material silt content (%)	5.1	EPA, *AP-42* , Volume I, Section 13.2.2 Unpaved Roads (9/98)
W = mean vehicle weight (tons)	35	Heavy truck weighs 70000 pounds-West Tavaputs Plateau EIS
W = mean vehicle weight (tons)	3.5	Light truck weighs 7000 lbs-West Tavaputs Plateau EIS
M = surface material moisture content (%)	2.4	AP-42 Table 11.9-3 as in Jonah EIS Table B.1.3
Control efficiency for watering (%) =	50	EPA, *Control of Open Fugitive Dust Sources* , Section 5.3.1 Watering of Unpaved Surfaces (1988)
P = Precipitation Days (>0.01" rainfall)	62	Precipitation days at Duchesne, UT from NCDC climatology

Fugitive Dust Emissions Estimation for Road and Well Pad Construction Traffic

Activity	Vehicle Type	Av. Vehicle Weight (lb)	# of Visits per Year	Total # of Round Trips	Round Trip Distance (mi)	Total Miles Traveled	PM_{10}		PM2.5	
							Em. Factor (lb/VMT)	Emissions (tpy/well)	Em. Factor (lb/VMT)	Emissions (tpy/well)
Travel to well	Light truck	7,000	8	8	20	160	0.21	0.02	0.02	0.00
Travel to well	Heavy Truck	70,000	4	4	20	80	0.66	0.03	0.07	0.00
						Total		**0.04**		**0.00**

Table A15: Construction Fugitive Dust Assumptions

Assumptions:
Watering control efficiency assumed to be 50%
Treat all equipment as bulldozer equivalents in terms of generating dust.
This is a conservative assumption, and was done in the West Tavaputs Plateau EIS.
Don't have information on soil moisture or silt content, so used values from AP-42 Table 11-9.3
for geometric means of these quantities.

Information from operators:
Total time to build the well pad is 8 days
For pad construction, we use 2 Cat D-8R Dozers, 2001, 2004; and one Champion 738 (14 ft. blade) Grader, 1999.
Hours of use = 70 per well pad. Tiers and emission factors unknown.

Equations

Emissions equations from AP-42 Table 11.9-1 for Bulldozing Overburden emissions, Western Surface Coal Mining

For TSP ≤ 30 microns:
Emissions (TSP lbs/hr) =[5.7 s^1.2 / M ^1.3] * Control Efficiency

For PM ≤ 15 microns:
Emissions (PM15 lbs/hr) =[1.0 s^1.5 / M ^1.4] * Control Efficiency

Emissions (PM10 lbs/hr) = PM15 * 0.75

Emissions (PM2.5 lbs/hr) = TSP * 0.105

Table A16: Well pad and Pipeline Construction Fugitive Dust Emissions

Construction Fugitive Dust Emissions per Well						
Units	**NOx**	**SO2**	**CO**	**VOC**	**PM10**	**PM2.5**
tons/well	0.0000	0.00000	0.0000	0.0000	0.0271	0.0149
lbs/hr	0.0000	0.0000	0.0000	0.0000	1.1291	0.6207

Well Pad and Pipeline Construction
Fugitive Dust Emissions Per Well (lbs/hr)

Equipment Type	TSP	PM10	PM2.5	PM15
CAT D-8 Dozer	1.970373	0.376	0.21	0.5018
Champion 738 Grader	1.970373	0.376	0.21	0.5018
Case 380 Backhoe	1.970373	0.376	0.21	0.5018
Total	5.9111	1.1291	0.6207	1.5055

Well Pad and Pipeline Construction
Fugitive Dust Emissions Per Well (tons/well)

Equipment Type	TSP	PM10	PM2.5	PM15
CAT D-8 Dozer	0.068963	0.013	0.01	0.0176
Champion 738 Grader	0.068963	0.013	0.01	0.0176
Case 380 Backhoe	0.003842	0.001	0.00	0.0010
Total	0.1418	0.0271	0.0149	0.0361

Well Pad and Pipeline Construction Equipment Utilization

Equipment Type	# Units	Tier Level	Model Year	Time Used Per Unit (hours)
CAT D-8 Dozer	2	0	2001, 2004	70
Champion 738 Grader	1	0	1999	70
Case 380 Backhoe	1	0		3.9

Parameters Used in Emission Equations		
Description	Parameter	Reference
Watering control efficiency	0.5	Moxa Arch AQTSD (BLM, 2007)
M=soil moisture content	7.9	(AP-42 Table 11.9-3)
s=Soil silt content	6.9	(AP-42 Table 11.9-3)
PM10 multiplier	0.75	(AP-42 Table 11.9-1)
PM2.5 multiplier	0.105	(AP-42 Table 11.9-1)

Table A17: Construction Wind Erosion Assumptions

Assumptions

Note that compressor station erosion emissions are not included in the emissions totals.
This is because we will model the peak year of emissions, which will be the final year of the project.
In order to be conservative, we will assume that all four compessor stations have already been built, since their production emissions are higher than their construction emissions.

Exposed surface type assumed to be flat.
Meteorological Data from Grand Junction 1947-1979. See Grand Junction Wind Data worksheet for data.
Fastest Mile Wind Speed U_{10}* = 23.30 m/s (Average over all years)
Assume 1 Disturbance per year i.e. no disturbance for reclamation

Equations

Friction Velocity U* = 0.053 U_{10}* (AP-42 Section 13.2.5.3 Equation 4)

Erosion Potential P (g/m^2-time) = 58(U*-U_t*)^2 + 25(U*-Ut*) for U*>U_t*; P=0 otherwise (AP-42 Section 13.2.5.3 Equation 3)

$$\text{Emissions (tons/yr)} = k * \frac{\text{Erosion Potential (g/m}^2\text{/year) * Disturbed Area (m}^2\text{) * (\#Disturbances/year)}}{\text{453.6 (g/lb) *2000 (lbs/ton)}}$$ (AP-42 Section 13.2.5.3 Equation 2)

k is a particle size multiplier that depends on the aerodynamic size of the particle (from AP-42 Section 13.2.5.3).

Table A18: Construction Wind Erosion Emissions

Construction Wind Erosion Emissions per Well			
tons/year		lbs/hr	
PM10	PM2.5	PM10	PM2.5
0.0449	1.9E-06	0.0102434	4.2562E-07

Control Efficiency: 50% 1 squ mile = 640 acres

From Ashley NF Master Plan, road Right of Way (ROW) will be 35 feet wide.
35 foot ROW = 0.0066 mile ROW
8 days for pad contruction, per operators, assume 12 hour workday
From Ashley NF Master Plan Operator plans to build 100 miles of new access roads and 21 miles of upgraded existing roads
New road per well = 0.303 miles
130 miles of new pipeline
New Pipeline per well= 0.325 miles But Operators expect no additional disturbance as pipe to be laid in road ROW.

Disturbed Area Per Well:

Well Pad Construction:	2.50 acres	10117.15 m^2
Central Compressor Construction:	1.50 acres	6070.29 m^2
Access Road Construction:	1.29 acres	5202.05 m^2
Pipeline Construction:	0.00 acres	0 m^2

Emission Calculations:

	Fastest Mile m/s	Maximum Friction Velocity	Well Erosion Potential g/m^2-time	Road Erosion Potential g/m^2-time	Disturbed Area m^2	PM_{10} Emissions (tons/year)	$PM_{2.5}$ Emissions (tons/year)
Well Pad Construction:	23.30	1.23	8.05		10117.15	0.04	1.9E-06
Central Compressor Construction	23.30	1.23	8.05		6070.29	0.03	6.7E-07
Resource Road Construction:	23.30	1.23		-1.85	5202.05	0.00	0.0E+00
Pipeline Construction:	23.30	1.23		-1.85	0.00	0.00	0.0E+00
Total:						**0.04**	**1.9E-06**

1.02 m/s = Threshold friction velocity for well pads (AP-42 Table 13.2.5-2 Overburden, Western Surface Coal Mine)
1.33 m/s = Threshold friction velocity for roads (AP-42 Table 13.2.5-2 Roadbed Material)
0.5 = Particle size multiplier for PM10
0.075 = Particle size multiplier for PM2.5

Table A19: Drilling Assumptions

Assumptions
Assumed PM supplied by operators is PM10
Assumed PM2.5=0.97PM10 as in NONROAD
Assumed drill rig engines are completely deteriorated

Information from Operators
Each rig is equipped with 5 Detroit Diesel Series 60 engines, manufactured in 2006 (Tier 3).
These engines are rated at 475 HP. Emission factors are NOx – 6.3 g/HP-Hr, CO 0.59 g/HP-Hr, VOC 0.09, PM 0.08, SOx 0.076 (assuming .05% sulfur fuel). Fuel is low sulfur diesel. Average load factor is about 65%. Engine time on per drilling event is 120 hours.

Deterioration Calculation Method from EPA (2004) p. 19
DF =deterioration factor=1+A^B
A=Relative Deterioration Factor (% increase/%useful life)
B = 1 for diesel nonroad engines
Emission factor = (Steady-state, zero hour emission factor) x (Deterioration Factor)
Assume engines are completely deteriorated

Table A20: Drilling Emissions

Drilling Emissions Per Drilling Event										
Units	**NOx**	**SO2**	**CO**	**VOC**	**PM10**	**PM2.5**	**PM_filt**	**PM_cond**	**CO2**	**CH4**
tons/well	1.297	0.016	0.139	0.019	0.024	0.023	0.009	0.015	107.445	0.065
lbs/hr	21.61	0.26	2.31	0.31	0.40	0.39	0.14	0.25	1790.75	1.09

Drilling Emissions (lbs/hr)

NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2	CH4
21.61	0.26	2.31	0.31	0.40	0.39	0.14	0.25	1790.75	1.09

Drilling Emissions (lbs/well)

NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2	CH4
2593.50	31.04	277.34	37.75	48.13	46.68	17.27	29.41	214890.00	130.60

Equipment Utilization

Equipment Type	# Units	Tier Level	Model Year	Time/Unit (hours)	HP	Load
Detroit Diesel Series 60 Engine	5	3	2006	120	475	0.65

Drilling Emission Factors (g/HP-hr) (supplied by Operators, except GHG, from AP42, Table 3.4-1)

NOx	SO2	CO	VOC	PM10	PM2.5	CO2	CH4
6.3	0.076	0.59	0.09	0.08	0.0776	526.176	3.20E-01

Tier 3+ Deterioration Factors from EPA (2004) NONROAD Table A4

Pollutant	DF	A
HC	1.027	0.027
CO	1.151	0.151
NOx	1.008	0.008
PM	1.473	0.473

Drill Rig Engine Emission Factors from AP-42 Table 3.4-1 in lbs/(hp-hr)

CO2	CH4
1.16	7.05E-04

Table A21: Drilling Road Traffic Assumptions

Assumptions
Emission factors taken from the Moxa Arch TSD (BLM, 2007)
50% PM control efficiency from watering unpaved surfaces

Data for Number of Days of Measurable (>0.01") Precipitation
Data assumed representative of project area from Western Regional Climate Center
for Duchesne, UT (data source nearest project area). Mean for data from 1928-2007 is
Measurable precip (>0.01") at Duchesne, UT 62 days/year
http://www.wrcc.dri.edu/htmlfiles/ut/ut.01.html

Information from Operators
Trip distance (off of pavement) will average about 10 miles each way for well, pipeline and compressor construction.
See attached Excel spreadsheet for number and type of trips anticipated for each phase of well development through production.
(attached Excel spreadsheet referenced above is included here as the Truck Traffic Worksheet)

Equations

$$\text{Emissions (tons/year-well)} \quad \frac{\text{Emission factor (g/mile) * \# Trips * Trip Distance (miles)}}{\text{453.5 (g/lb) * 2000 (lbs/ton)}}$$

$$\text{Emissions [lb/VMT]} = \frac{k(s/12)^a(W/3}{(M/0.2)^c} * \frac{(365-P)}{365} \text{ *(Control Efficiency)}$$

Table A22: Drilling Road Traffic Emissions

Drilling Road Traffic Emissions Per Well								
Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
tons/well	0.0147	0.0011	0.0543	0.0115	0.7948	0.0829	0.001	0.002
lbs/hr	0.0034	0.0002	0.0124	0.0026	0.1815	0.0189	0.0003	0.0005

Drilling Road Traffic Exhaust Emissions (tons/year-well)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
Light Truck	0.002	0.000	0.020	0.001	0.000	0.000	5.42E-05	9.23E-05
Heavy Truck	0.013	0.001	0.035	0.010	0.004	0.004	1.36E-03	2.31E-03
Total	0.015	0.001	0.054	0.012	0.004	0.004	0.001	0.002

Equipment Utilization

Equipment Type	Round Trip Off-Road Trip Distance (miles)	Number of Round Trips per well
Light Truck	20	88
Heavy Truck	20	92

Emission Factors for Exhaust from Drilling Road Traffic

Vehicle	Emission Factors (g/mi)							
Type	Class	Model Year	NO_x	PM_{10} [b,c]	$PM_{2.5}$ [b,c]	SO_x [a]	CO	VOC
Light-Duty Gasoline Truck	LDGT2	1999+	0.79	0.10	0.08	0.21	10.15	0.63
Heavy-Duty Diesel Truck	HDDV	2001+	6.49	1.96	1.81	0.32	17.06	5.08

NOx, VOC, and CO Source: EPA, *AP-42* , Volume II, Appendix H-117, Table 3.1A.2 Light Duty Gasoline Powered Trucks II and Appendix H-259, Table 7.1.2 Heavy Duty Diesel Powered Vehicles (High Altitude; 50,000 mileage) (6/30/95).

[a] Method from MOBILE6.1 Particulate Emission Factor Model Technical Description EPA420-R-02-012 March 2002, equation 3.7

[b] Including tire and brake wear emissions.

[c] From Moxa Arch TSD, taken from BLM, 2003, APP_A21, table 1.1.2.2, estimated using EPA PART5 Model (1995)

Fugitive Dust Emissions Associated with Drilling Traffic To Well

Source for Data for Constants: EPA (1995), AP-42, Section 13.2.2 Unpaved Roads (9/98). Table 13.2.2-2.

$$E\ [\text{lb/VMT}] = \frac{k(s/12)^{a}(W/3)^{d}}{(M/0.2)^{c}} \ * \frac{(365-P)}{365} \ *(\text{Control Efficiency})$$

Constant	PM_{10}	$PM_{2.5}$
k	1.8	0.18
a	1	1
d	0.5	0.5
c	0.2	0.2

Variable Description	Assumed Value	Reference
E = size-specific emission factor (lb/VMT)		
s = surface material silt content (%)	5.1	EPA, *AP-42* , Volume I, Section 13.2.2 Unpaved Roads (9/98)
W = mean vehicle weight (tons)	35	Heavy truck weighs 45000 pounds
W = mean vehicle weight (tons)	3.5	Pickup truck weighs 7000 lbs
M = surface material moisture content (%)	2.4	AP-42 Table 11.9-3 as in Jonah EIS Table B.1.3
Control efficiency for watering (%) =	50	EPA, *Control of Open Fugitive Dust Sources* , Section 5.3.1 Watering of Unpaved Surfaces (1988)
P = Precipitation Days (>0.01" rainfall)	62	Precipitation days at Duchesne, UT from NCDC climatology

Fugitive Dust Emissions Estimation for Drilling Road Traffic on Unpaved Roads

Activity	Vehicle Type	Av. Vehicle Weight (lb)	# of Visits per Year	Total # of Round Trips	Round Trip Distance (mi)	Total Miles Traveled	PM_{10}		PM2.5	
							Em. Factor (lb/VMT)	Emissions (tpy/well)	Em. Factor (lb/VMT)	Emissions (tpy/well)
Travel to well	Light truck	7000	88	88	20	1760	0.21	0.18	0.02	0.02
Travel to well	Heavy Truck	70,000	92	92	20	1,840	0.66	0.61	0.07	0.06
						Total		**0.79**		**0.08**

Table A23: Completion Assumptions

Assumptions

Well Completion done in two phases: fracturing and completion
See guidance from operators below in red print
BSFC = 0.367 lbs/hp-hr (NONROAD Factor from EPA, 2004)
Operators' guidance is that engines will be Tier II or III-going with Tier II to be conservative.
Operators supplied load factor for completion rig-used this load factor for all other equipment, absent other information

Information from Operators

This equipment is typically run sporadically over the course of one 12-hour day as each stage is completed. In total, these pieces of equipment run about 4 hours to frac each well. After one day on a well site, this equipment moves offsite to another location. I do not have emission factors for these engines,
but was told the engines vary in age. In general, the engines should be assumed to be Tier 2 or Tier 3.

<u>Completion Rig usage:</u>

For well completions on the proposed project, Berry will use three completion rigs at a given time. Following fracturing, the completion rigs are used for four (4) 12-hour days (48 operating hours). I do not have emissions factors for the completion rig engines.
The completion rigs currently utilized feature Detroit Diesel engines, dated 2001, 2005, and 2007.
These engines are rated at 515 HP. Typical load factor for these engines is 50%.

Deterioration Calculation Method from EPA (2004) p. 19

DF =deterioration factor=1+A^B
A=Relative Deterioration Factor (% increase/%useful life)
B = 1 for diesel nonroad engines
Emission factor = (Steady-state, zero hour emission factor) x (Deterioration Factor)
Assume engines are completely deteriorated

Table A24: Completion Emissions

Completion and Fracing Emissions per Well									
Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
tons/well	0.085	0.000	0.018	0.004	0.004	0.004	0.001	0.002	10.422
lbs/hr	42.15	0.05	9.13	1.95	1.96	1.90	0.70	1.20	5359.28

Completion and Fracing Emissions (lbs/hr)

Equipment Type	NOx	SO2	CO	HC	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
Frac Pumps	30.10	0.04	6.12	1.26	1.35	1.41	1.37	0.51	0.86	3859.54
Blender	3.19	0.00	1.13	0.13	0.14	0.15	0.15	0.05	0.09	409.34
Hydration Unit	2.89	0.00	0.61	0.11	0.12	0.13	0.12	0.05	0.08	350.87
Chem Add	1.69	0.00	0.36	0.07	0.07	0.07	0.07	0.03	0.05	204.67
Sandmaster	0.68	0.00	0.16	0.06	0.06	0.03	0.03	0.01	0.02	87.63
Wire line truck	1.11	0.00	0.23	0.09	0.09	0.05	0.05	0.02	0.03	146.07
Completion Rigs	2.48	0.00	0.53	0.10	0.11	0.11	0.11	0.04	0.07	301.16
Total	42.15	0.05	9.13	1.81	1.95	1.96	1.90	0.70	1.20	5359.28

Completion and Fracing Emissions (lbs/well)

Equipment Type	NOx	SO2	CO	HC	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
Frac Pumps	45.14	0.053	9.18	1.88	2.02	2.12	2.05	0.76	1.29	5789.30
Blender	1.60	0.002	0.56	0.07	0.07	0.07	0.07	0.03	0.05	204.67
Hydration Unit	1.45	0.002	0.31	0.06	0.06	0.06	0.06	0.02	0.04	175.43
Chem Add	0.84	0.001	0.18	0.03	0.04	0.04	0.04	0.01	0.02	102.34
Sandmaster	0.34	0.000	0.08	0.03	0.03	0.02	0.02	0.01	0.01	43.81
Wire line truck	0.56	0.001	0.11	0.04	0.05	0.03	0.03	0.01	0.02	73.04
Completion Rigs	119.19	0.133	25.28	4.70	5.05	5.28	5.12	1.90	3.23	14455.72
Total	169.12	0.19	35.70	6.82	7.32	7.62	7.39	2.73	4.65	20844.31

Completion and Fracing Equipment Utilization				
Equipment Type	# Units	HP	Time	Load
Frac Pumps	3	2200	1.5	0.5
Blender	1	700	0.5	0.5
Hydration Unit	1	600	0.5	0.5
Chem Add	1	350	0.5	0.5
Sandmaster	1	150	0.5	0.5
Wire line truck	1	250	0.5	0.5
Completion Rigs	1	515	48	0.5

Susan Kemball-Cook: assuming one rig per well, operator says total of four rigs to be used for entire project

Susan Kemball-Cook: per operators

Emissions Factor (g/hp-hr)								
Equipment Type	NOx	SO2	CO	HC	VOC	PM10	PM2.5	CO2
Frac Pumps	4.1	0.004877	0.7642	0.1669	0.175746	0.1316	0.127652	530.5107
Blender	4.1	0.004877	1.3272	0.1669	0.175746	0.1316	0.127652	530.5107
Hydration Unit	4.3351	0.004877	0.8425	0.1669	0.175746	0.1316	0.127652	530.5107
Chem Add	4.3351	0.004877	0.8425	0.1669	0.175746	0.1316	0.127652	530.5107
Sandmaster	4.1	0.004872	0.8667	0.3384	0.356335	0.1316	0.127652	529.9636
Wire line truck	4	0.004873	0.7475	0.3085	0.324851	0.1316	0.127652	530.059
Completion Rigs	4.3351	0.004877	0.8425	0.1669	0.175746	0.1316	0.127652	530.5107

Crankcase Emission Factors (g/hp-hour)

	HC	VOC
Frac Pumps	0.0033	0.00351
Blender	0.0033	0.00351
Hydration Unit	0.0033	0.00351
Chem Add	0.0033	0.00351
Sandmaster	0.0068	0.00713
Wire line truck	0.0062	0.00650
Completion Rigs	0.0033	0.00351

Tier II Deterioration Factors from NONROAD Model Appendix A4

	DF	A
HC	1.034	0.034
CO	1.101	0.101
NOx	1.009	0.009
PM	1.473	0.473

DF =deterioration factor=$1+A^{B}$
A=Relative Deterioration Factor (% increase/%useful life)
B = 1 for diesel nonroad engines
Emission factor = (Steady-state, zero hour emission factor) x (Deterioration Factor)
Assume are completely deteriorated

Table A25: Completion Road Traffic Assumptions

Assumptions

Data assumed representative of project area from Western Regional Climate Center
for Duchesne, UT (data source nearest project area). Mean for data from 1928-2007 is
Measurable precip (>0.01") at Duchesne, UT = 62 days/year
http://www.wrcc.dri.edu/htmlfiles/ut/ut.01.html

Emission factors taken from the Moxa Arch TSD (BLM, 2007)
50% PM control efficiency from watering unpaved surfaces

Information from Operators

Trip distance (off of pavement) will average about 10 miles each way for well, pipeline and compressor construction.
See attached Excel spreadsheet for number and type of trips anticipated for each phase of well development through production.
(attached Excel spreadsheet referenced above is included here as the Truck Traffic Worksheet)

Equations

$$\text{Emissions (tons/year-well)} = \frac{\text{Emission factor (g/mile)} * \text{\# Trips} * \text{Trip Distance (miles)}}{453.5 \text{ (g/lb)} * 2000 \text{ (lbs/ton)}}$$

$$\text{Emissions [lb/VMT]} = \frac{k(s/12)^a(W/3)^d}{(M/0.2)^c} * \frac{(365-P)}{365} * (\text{Control Efficiency})$$

$$SO_2 \text{ Emission Factor (g/mile)} = \frac{\text{Fuel Density (lbs/gallon)} * (453.6 \text{ g/lb}) * \text{Fuel Sulfur Content} * 2}{\text{Vehicle Fuel Efficiency (miles/gallon)}}$$

Diesel fuel sulfur content assumed to be 0.05% per operators
Diesel fuel density assumed to be 7.08 lbs/gallon (As in West Tavaputs EIS)
Heavy truck fuel efficiency = 10 miles/gallon (As in West Tavaputs EIS)
Light truck fuel efficiency = 15 miles/gallon (As in West Tavaputs EIS)
Factor of 2 is the weight ratio of SO_2 to sulfur

Table A26: Completion Road Traffic Emissions

Completion Road Traffic Emissions per Well

Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
tons/well	0.0118	0.0008	0.0400	0.0092	0.6113	0.0639	0.0012	0.0021
lbs/hr	0.0027	0.0002	0.0091	0.0021	0.1396	0.0146	0.0003	0.0005

Exhaust Emissions (tons/year-well)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
Light Truck	8.87E-04	2.41E-04	1.14E-02	7.13E-04	1.11E-04	8.49E-05	3.14E-05	5.77E-05
Heavy Truck	1.09E-02	5.38E-04	2.86E-02	8.50E-03	3.29E-03	3.03E-03	1.12E-03	2.06E-03

Equipment Utilization

Equipment Type	Round Trip Off-Road Trip Distance (miles)	Number of Round Trips per well
Light Truck	20	51
Heavy Truck	20	76

Emission Factors for Exhaust from Road Traffic

Vehicle Type	Emission Factors (g/mi)							
	Class	Model Year	NO_x	PM_{10} [b,c]	$PM_{2.5}$ [b,c]	SO_x [a]	CO	VOC
Light-Duty Gasoline Truck	LDGT2	1999+	0.79	0.10	0.08	0.21	10.15	0.63
Heavy-Duty Diesel Truck	HDDV	2001+	6.49	1.96	1.81	0.32	17.06	5.08

NOx, VOC, and CO Source: EPA, *AP-42* , Volume II, Appendix H-117, Table 3.1A.2 Light Duty Gasoline Powered Trucks II and Appendix H-259, Table 7.1.2 Heavy Duty Diesel Powered Vehicles (High Altitude; 50,000 mileage) (6/30/95).

[a] Method from MOBILE6.1 Particulate Emission Factor Model Technical Description EPA420-R-02-012 March 2002, equation 3.7

[b] Including tire and brake wear emissions.

[c] From Moxa Arch TSD, taken from BLM, 2003, APP_A21, table 1.1.2.2, estimated using EPA PART5 Model (1995)

Fugitive Dust Emissions Associated with Production Traffic To Well on Unpaved Roads

Source for Data for Constants: EPA (1995), AP-42, Section 13.2.2 Unpaved Roads (9/98). Table 13.2.2-2.

$$E\ [lb/VMT] = \frac{k(s/12)^a (W/3)^d}{(M/0.2)^c} \ast \frac{(365-P)}{365} \ast (\text{Control Efficiency})$$

Constant	PM_{10}	$PM_{2.5}$
k	1.8	0.18
a	1	1
d	0.5	0.5
c	0.2	0.2

Variable Description	Value	Reference
E = size-specific emission factor (lb/VMT)		
s = surface material silt content (%)	5.1	EPA, *AP-42* , Volume I, Section 13.2.2 Unpaved Roads (9/98)
W = mean vehicle weight (tons)	35	Heavy truck weighs 45000 pounds
W = mean vehicle weight (tons)	3.5	Pickup truck weighs 7000 lbs
M = surface material moisture content (%)	2.4	AP-42 Table 11.9-3 as in Jonah EIS Table B.1.3
Control efficiency for watering (%) =	50	EPA, *Control of Open Fugitive Dust Sources* , Section 5.3.1 Watering of Unpaved Surfaces (1988)
P = Precipitation Days (>0.01" rainfall)	62	Precipitation days at Duchesne, UT from NCDC climatology

Fugitive Dust Emissions Estimation for Completion Road Traffic

Activity	Vehicle Type	Av. Vehicle Weight (lb)	# of Visits per Year	Total # of Round Trips	Round Trip Distance (mi)	Total Miles Traveled	PM_{10} Em. Factor (lb/VMT)	PM_{10} Emissions (tpy/well)	PM2.5 Em. Factor (lb/VMT)	PM2.5 Emissions (tpy/well)
Travel to well	Light truck	7000	51	51	20	1020	0.21	0.11	0.02	0.01
Travel to well	Heavy Truck	70,000	76	76	20	1,520	0.66	0.50	0.07	0.05
							Total	**0.61**		**0.06**

Table A27: Assumptions for Road Traffic for Installing Production Equipment

Assumptions

Data assumed representative of project area from Western Regional Climate Center
for Duchesne, UT (data source nearest project area). Mean for data from 1928-2007 is
Measurable precip (>0.01") at Duchesne, UT 62 days/year
http://www.wrcc.dri.edu/htmlfiles/ut/ut.01.html

Emission factors taken from the Moxa Arch TSD (BLM, 2007)
50% PM control efficiency from watering unpaved surfaces

Information from Operators
Trip distance (off of pavement) will average about 10 miles each way for well, pipeline and compressor construction.
See attached Excel spreadsheet for number and type of trips anticipated for each phase of well development through production.
(attached Excel spreadsheet referenced above is included here as the Truck Traffic Worksheet)

Equations

Emissions (tons/year-well) $\dfrac{\text{Emission factor (g/mile) * \# Trips * Trip Distance (miles)}}{\text{453.5 (g/lb) * 2000 (lbs/ton)}}$

Emissions [lb/VMT] = $\dfrac{k(s/12)^a(W/3}{(M/0.2)^c} \; \dfrac{*(365-P)}{365} \; \text{*(Control Efficiency)}$

SO_2 Emission Factor (g/mi $\dfrac{\text{Fuel Density (lbs/gallon) * (453.6 g/lb) * Fuel Sulfur Content * 2}}{\text{Vehicle Fuel Efficiency (miles/gallon)}}$

Diesel fuel sulfur content assumed to be 0.05% per operators
Diesel fuel density assumed to be 7.08 lbs/gallon (As in West Tavaputs EIS)
Heavy truck fuel efficiency = 10 miles/gallon (As in West Tavaputs EIS)
Light truck fuel efficiency = 15 miles/gallon (As in West Tavaputs EIS)
Factor of 2 is the weight ratio of SO_2 to sulfur

Table A28: Emissions from Road Traffic Installing Production Equipment

Production Equipment Install Road Traffic Emissions Per Well

Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
tons/well	0.0022	0.0002	0.0084	0.0018	0.1222	0.0127	0.00021503	0.0003661
lbs/hr	0.0005	0.0000	0.0019	0.0004	0.0279	0.0029	0.0000	0.0001

Production Equipment Installation Traffic Exhaust Emissions (tons/year-well)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
Light Truck	0.0002	0.00007	0.00313	0.00020	0.00003	0.00002	8.62E-06	1.47E-05
Heavy Truck	0.0020	0.00010	0.00527	0.00157	0.00061	0.00056	2.06E-04	3.51E-04

Equipment Utilization

Equipment Type	Round Trip Off-Road Trip Distance (miles)	Number of Round Trips per well
Light Truck	20	14
Heavy Truck	20	14

Emission Factors for Exhaust from Road Traffic

Vehicle	Emission Factors (g/mi)							
Type	Class	Model Year	NO_x	PM_{10} [b,c]	$PM_{2.5}$ [b,c]	SO_x [a]	CO	VOC
Light-Duty Gasoline Truck	LDGT2	1999+	0.79	0.10	0.08	0.21	10.15	0.63
Heavy-Duty Diesel Truck	HDDV	2001+	6.49	1.96	1.81	0.32	17.06	5.08

NOx, VOC, and CO Source: EPA, *AP-42* , Volume II, Appendix H-117, Table 3.1A.2 Light Duty Gasoline Powered Trucks II and Appendix H-259, Table 7.1.2 Heavy Duty Diesel Powered Vehicles (High Altitude; 50,000 mileage) (6/30/95).

[a] Method from MOBILE6.1 Particulate Emission Factor Model Technical Description EPA420-R-02-012 March 2002, equation 3.7

[b] Including tire and brake wear emissions.

[c] From Moxa Arch TSD, taken from BLM, 2003, APP_A21, table 1.1.2.2, estimated using EPA PART5 Model (1995)

Fugitive Dust Emissions Associated with Production Traffic To Well on Unpaved Roads

Source for Data for Constants: EPA (1995), AP-42, Section 13.2.2 Unpaved Roads (9/98). Table 13.2.2-2.

$$E\ [lb/VMT] = \frac{k(s/12)^a(W/3)^d}{(M/0.2)^c} \ast \frac{(365-P)}{365} \ast (\text{Control Efficiency})$$

Constant	PM_{10}	$PM_{2.5}$
k	1.8	0.18
a	1	1
d	0.5	0.5
c	0.2	0.2

Variable Description	Value	Reference
E = size-specific emission factor (lb/VMT)		
s = surface material silt content (%)	5.1	EPA, *AP-42* , Volume I, Section 13.2.2 Unpaved Roads (9/98)
W = mean vehicle weight (tons)	35	Heavy truck weighs 45000 pounds
W = mean vehicle weight (tons)	3.5	Pickup truck weighs 7000 lbs
M = surface material moisture content (%)	2.4	AP-42 Table 11.9-3 as in Jonah EIS Table B.1.3
Control efficiency for watering (%) =	50	EPA, *Control of Open Fugitive Dust Sources* , Section 5.3.1 Watering of Unpaved Surfaces (1988)
P = Precipitation Days (>0.01" rainfall)	62	Precipitation days at Duchesne, UT from NCDC climatology

Fugitive Dust Emissions Estimation for Completion Road Traffic

Activity	Vehicle Type	Av. Vehicle Weight (lb)	# of Visits per Year	Total # of Round Trips	Round Trip Distance (mi)	Total Miles Traveled	PM_{10}		PM2.5	
							Em. Factor (lb/VMT)	Emissions (tpy/well)	Em. Factor (lb/VMT)	Emissions (tpy/well)
Travel to well	Light truck	7000	14	14	20	280	0.21	0.03	0.02	0.00
Travel to well	Heavy Truck	70,000	14	14	20	280	0.66	0.09	0.07	0.01
Total								**0.12**		**0.01**

Table A29: Compressor Station Construction Assumptions

Assumptions:
Emission factors from (EPA, 2004; EPA420-P-04-009) p. A-7
Crankcase Emission factors are 2% of HC Exhaust Emission Factor for Tier II and earlier per
EPA NONROAD Modeling Guidance p. 23 (EPA, 2004; EPA420-P-04-009).
VOC/THC= 1.053 Conversion for HC->VOC for diesel engines (EPA, 2005; EPA420-R-05-0159, p. 5)
Loads based on Appendix B of the Jonah EIS Table B.1.4-Taken from "Surface Mining" (Pfleider 1972) for average service duty.
The overall load factor is 0.4 for motor grader and D8 Dozer for Jonah EIS
Load factor is 0.4 for well pad heavy construction equipment for West Tavaputs EIS (2007)
HP not available from operators, so estimated HP from comparable models
Since engine tiers are unknown (see operator information below), assumed Tier 0
Per USPS Guidance, 37% of fine particles assumed to be filterable and all filterable are assigned to EC
Per USPS Guidance, 63% of fine particles assumed to be filterable and all filterable are assigned toSOA
Scale emissions by ratio of well pad to compressor station pad areas= 0.6

Information from operators :
Total time to build the well pad is 8 days
For pad construction, we use 2 Cat D-8R Dozers, 2001, 2004; and one Champion 738 (14 ft. blade) Grader, 1999.
Hours of use = 70 per well pad. Tiers and emission factors unknown.

Equations:

$$\text{Emissions (tons/year-well)} = \frac{\text{Emission factor (g/hp-hr)} * \text{Horsepower} * \text{Time Used (hours)} * \text{Load}}{453.5 \text{ (g/lb)} * 2000 \text{ (lbs/ton)}}$$

Deterioration Calculation Method from EPA (2004) p. 19
DF = deterioration factor=$1+A^B$
A = Relative Deterioration Factor (% increase/%useful life)
B = 1 for diesel nonroad engines
Emission factor = (Steady-state, zero hour emission factor) x (Deterioration Factor)
Assume engines are completely deteriorated

Table A30: Compressor Station Construction Emissions

Compressor Station Construction Emissions Per Station

Units	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
tons/well	0.1247	0.0001	0.0465	0.0111	0.0068	0.0066	0.0024	0.0041	7.6883
lbs/hr	3.5641	0.0020	1.3289	0.3176	0.1933	0.1875	0.0694	0.1181	219.6646

Compressor Station Construction Equipment Exhaust Emissions Per Station (lbs/hr)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
CAT D-8 Dozer	4.7	0.0	1.7	0.4	0.3	0.2	0.1	0.2	289.2
Champion 738 Grader	1.2	0.0	0.5	0.1	0.1	0.1	0.024	0.041	77.0
Total	5.9	0.00	2.2	0.5	0.3	0.3	0.1	0.2	366.1

Compressor Station Construction Equipment Exhaust Emissions Per Station (lbs/year-well)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	CO2
CAT D-8 Dozer	328.4	0.19	122.5	29.3	17.8	17.3	6.4	10.9	20240.9
Champion 738 Grader	87.4	0.05	32.6	7.8	4.7	4.6	1.7	2.9	5386.7
Total	415.8	0.24	155.0	37.1	22.6	21.9	8.1	13.8	25627.5

Compressor Station Construction Equipment Utilization

Equipment Type	# Units	Tier Level	Model Year	Time Used Per Unit (hours)	HP	Load (%)	BSFC (lb/hp-hr)
CAT D-8 Dozer	2	0	2001, 2004	70	310	0.4	0.367
Champion 738 Grader	1	0	1999	70	165	0.4	0.367

Compressor Station Construction Equipment Exhaust Steady-State, Zero Hour Emission Factors

Equipment Type	NOx (g/hp-hr)	SO_2 (g/hp-hr)	CO (g/hp-hr)	HC (g/hp-hr)	VOC (g/hp-hr)	PM10 (g/hp-hr)	PM2.5 (g/hp-hr)	CO_2 (g/hp-hr)
CAT D-8 Dozer	8.4	0.0049	2.7	0.68	0.71604	0.315985	0.306505	528.8739
Champion 738 Grader	8.4	0.0049	2.7	0.68	0.71604	0.315985	0.306505	528.8739

NOx, CO, HC, PM Emission factors from EPA (2004) Table A-2, Zero Hour Steady State Emission Factors for Nonroad CI Engines.
SO_2 emission factor calculated from EPA (2004) Equation 7. See below for description of method.

Crankcase Emission Factors (g/hp-hour)

Equipment Type	HC Tier 0	VOC Tier 0
CAT D-8 Dozer	0.0136	0.0143
Champion 738 Grader	0.0136	0.0143

Tier 0 Deterioration Factors from EPA (2004) NONROAD Table A4

	DF	A
HC	1.047	0.047
CO	1.185	0.185
NOx	1.024	0.024
PM	1.473	0.473

EPA NONROAD Model SO2 Emission Factor methodology (EPA, 2004; p. 22)

SO2 Emission Factor Calculation Information			
Fuel sulfur content (ppm)		15	specified by Berry operators
soxdsl		0.0015	sulfur fuel weight percent
soxcnv	Tiers I-III	0.02247	grams PM sulfur/grams fuel sulfur consumed
soxcnv	Tier IV	0.3	
grams PM sulfate/grams PM sulfur		7	
soxbas		0.33	NONROAD default certification sulfur fuel weight percent (3300 ppm)

EPA NONROAD Model CO2 Emission Factor methodology (EPA, 2004; p. 22)

Table A31: Compressor Station Construction Road Traffic Assumptions

Assumptions

BLM, 2003 after (EPA, *AP-42*, Volume I, Section 13.2.2 Unpaved Roads (9/98))
Heavy truck weighs 70000 pounds. Average of haul, logging and mud/water truck weights from West Tavaputs EIS
Light truck weighs 8000 lbs, per West Tavaputs EIS
AP-42 Table 11.9-3 as in Jonah EIS Table B.1.3
EPA, *Control of Open Fugitive Dust Sources*, Section 5.3.1 Watering of Unpaved Surfaces (1988)
Scale emissions by ratio of well pad to compressor station pad areas= 0.6
Data for Number of Days of Measurable (>0.01") Precipitation
Data assumed representative of project area from Western Regional Climate Center
for Duchesne, UT (data source nearest project area). Mean for data from 1928-2007 is
Measurable precip (>0.01") occurred on 62 days/year
http://www.wrcc.dri.edu/htmlfiles/ut/ut.01.html

Information from operators
Project area lies approximately 10 miles south of Duchesne, UT
Operators supplied truck traffic estimates-see Truck Traffic worksheet

Equations

$$\text{Emissions (tons/year-well)} = \frac{\text{Emission factor (g/mile)} * \text{\# Trips} * \text{Trip Distance (miles)}}{453.5\ \text{(g/lb)} * 2000\ \text{(lbs/ton)}}$$

$$\text{Emissions [lb/VMT]} = \frac{k(s/12)^a(W/3}{(M/0.2)^c} \; * \frac{(365-P)}{P} \; * \text{(Control Efficiency)}$$

$$SO_2 \text{ Emission Factor (g/mile)} = \frac{\text{Fuel Density (lbs/gallon)} * \text{(453.6 g/lb)} * \text{Fuel Sulfur Content} * 2}{\text{Vehicle Fuel Efficiency (miles/gallon)}}$$

Diesel fuel sulfur content assumed to be 0.05% per operators
Diesel fuel density assumed to be 7.08 lbs/gallon (As in West Tavaputs EIS)
Heavy truck fuel efficiency = 10 miles/gallon (As in West Tavaputs EIS)
Light truck fuel efficiency = 15 miles/gallon (As in West Tavaputs EIS)
Factor of 2 is the weight ratio of SO_2 to sulfur

Table A32: Compressor Station Construction Road Traffic Emissions

Compressor Station Construction Road Traffic Emissions per Station								
Units	**NOx**	**SO2**	**CO**	**VOC**	**PM10**	**PM2.5**	**PM_filt**	**PM_cond**
tons/well	0.0004	0.0000	0.0020	0.0003	0.0260	0.0027	3.8E-05	6.5E-05
lbs/hr	0.00010	0.00001	0.00045	0.00008	0.00593	0.00061	0.00001	0.00001

Compressor Station Construction Traffic Exhaust Emissions (tons/year-well)

Equipment Type	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond
Light Truck	0.0001	0.00004	0.00179	0.00011	0.00002	0.00001	4.9E-06	8.4E-06
Heavy Truck	0.0006	0.00003	0.00150	0.00045	0.00017	0.00016	5.9E-05	1.0E-04
Total	0.0007	0.0001	0.0033	0.0006	0.0002	0.0002	6.4E-05	1.1E-04

Equipment Utilization

Equipment Type	Round Trip Off-Road Trip Distance (miles)	Number of Round Trips Per Station
Light Truck	20	8
Heavy Truck	20	4
Total	40	12

Emission Factors for Exhaust from Road Traffic

Vehicle Type	Emission Factors (g/mi)							
	Class	Model Year	NO_x	PM_{10} [b,c]	$PM_{2.5}$ [b,c]	SO_x [a]	CO	VOC
Light-Duty Gasoline Truck	LDGT2	1999+	0.79	0.10	0.08	0.21	10.15	0.63
Heavy-Duty Diesel Truck	HDDV	2001+	6.49	1.96	1.81	0.32	17.06	5.08

NOx, VOC, and CO EF Source: EPA, *AP-42* , Volume II, Appendix H-117, Table 3.1A.2 Light Duty Gasoline Powered Trucks II and Appendix H-259, Table 7.1.2 Heavy Duty Diesel Powered Vehicles (High Altitude; 50,000 mileage) (6/30/95).

[a] Method from MOBILE6.1 Particulate Emission Factor Model Technical Description EPA420-R-02-012 March 2002, equation 3.7

[b] Including tire and brake wear emissions.

[c] From Moxa Arch TSD, taken from BLM, 2003, APP_A21, table 1.1.2.2, estimated using EPA PART5 Model (1995)

Fugitive Particulate Emissions Associated with Construction Traffic To Station

Source for Data for Constants: EPA (1995), AP-42, Section 13.2.2 Unpaved Roads (9/98). Table 13.2.2-2.

$$E\ [\text{lb/VMT}] = \frac{k(s/12)^a(W/3)^d}{(M/0.2)^c} * \frac{(365-P)}{365} * (\text{Control Efficiency})$$

Constant	PM_{10}	$PM_{2.5}$
k	1.8	0.18
a	1.00	1.00
d	0.50	0.50
c	0.2	0.2

Variable Description	Value	Reference
E = size-specific emission factor (lb/VMT)		
s = surface material silt content (%)	5.1	EPA, *AP-42* , Volume I, Section 13.2.2 Unpaved Roads (9/98)
W = mean vehicle weight (tons)	35	Heavy truck weighs 70000 pounds-West Tavaputs Plateau EIS
W = mean vehicle weight (tons)	3.5	Light truck weighs 7000 lbs-West Tavaputs Plateau EIS
M = surface material moisture content (%)	2.4	AP-42 Table 11.9-3 as in Jonah EIS Table B.1.3
Control efficiency for watering (%) =	50	EPA, *Control of Open Fugitive Dust Sources* , Section 5.3.1 Watering of Unpaved Surfaces (1988)
P = Precipitation Days (>0.01" rainfall)	62	Precipitation days at Duchesne, UT from NCDC climatology

Fugitive Dust Emissions Estimation for Compressor Station Construction Traffic

Activity	Vehicle Type	Av. Vehicle Weight (lb)	# of Visits per Year	Total # of Round Trips	Round Trip Distance (mi)	Total Miles Traveled	PM_{10}		PM2.5	
							Em. Factor (lb/VMT)	Emissions (tpy/well)	Em. Factor (lb/VMT)	Emissions (tpy/well)
Travel to well	Light truck	7,000	8	8	20	160	0.21	0.02	0.02	0.00
Travel to well	Heavy Truck	70,000	4	4	20	80	0.66	0.03	0.07	0.00
						Total		**0.04**		**0.00**

Table A33: Heater Emissions Assumptions

Assumptions

Set SO_2 emissions to zero because fuel content of sulfur is 0 according to operators' gas composition analysis

Each well site has two crude oil tanks
Each tank has a heater
Assume no controls on the heater

Information from the Operators

Per the Operator, each tank has a 500,000 btu/hr Natco heater operating 2500 hours/year
For tank heater emissions, assume that the gas has a heating value 1165.8 Btu/scf per gas composition analysis supplied by the operators

Equations

$$\text{Emissions (tons/year)} = \frac{\text{Emission Factor (lbs/MMscf)} * \text{Heater Size (Btu/hr)} * \text{Time On (Hours/Year)}}{\text{Fuel Heat Value (Btu/scf)} * 1\text{x}10^6 \text{ (scf/MMscf)} * 2000 \text{ (lbs/ton)}}$$

Table A34: Heater Emissions

Emissions from Well-Site Heaters Per Well																
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	HCHO	Benzene	Toluene	hyl Benze	Xylene	n-Hexane	CO2	CH4	Units
0.11	0.00	0.09	0.01	0.01	0.01	0.00	0.01	8.0E-05	2.3E-06	3.6E-06	0.0E+00	0.0E+00	0.0E+00	1.3E+02	2.5E-03	tons/well
0.0858	0.0000	0.0721	0.0047	0.0065	0.0065	0.0016	0.0049	0.0001	1.8E-06	2.9E-06	0.0E+00	0.0E+00	0.0E+00	1.0E+02	2.0E-03	lbs/hr

Heaters

Per the Operator, each tank has a 500,000 btu/hr Natco heater operating 2500 hours/year
For tank heater emissions, assume that the gas has a heating value of 1165.8 Btu/scf per gas composition analysis supplied by the operators
Assume no controls on the heater

Equipment Type	Heat Input (Btu/hr)	# Units	Time Used per unit (hours)
NATCO	500000	2	2500

Emissions (lbs/hr) for Natural Gas-Fired Heaters															
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	HCHO	Benzene	Toluene	hyl Benze	Xylene	n-Hexane	CO2	CH4
0.0858	0.0000	0.0721	0.0047	0.0065	0.0065	0.0016	0.0049	0.0001	1.8E-06	2.9E-06	0.0E+00	0.0E+00	0.0E+00	1.0E+02	2.0E-03

Emissions (tons/well) for Natural Gas-Fired Heaters															
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	HCHO	Benzene	Toluene	hyl Benze	Xylene	n-Hexane	CO2	CH4
0.11	0.00	0.09	0.01	0.01	0.01	0.00	0.01	8.0E-05	2.3E-06	3.6E-06	0.0E+00	0.0E+00	0.0E+00	1.3E+02	2.5E-03

Emission Factors for Natural Gas Fired Heaters (lb/MMscf) (from AP-42 Tables 1.4-1 and 1.4-2)															
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	HCHO	Benzene	Toluene	hyl Benze	Xylene	n-Hexane	CO2	CH4
100	0.6	84	5.5	7.6	7.6	1.9	5.7	7.5E-02	2.1E-03	3.4E-03	0.0E+00	0.0E+00	0.0E+00	120000	2.3

Table A35: Artificial Lift Engines Assumptions

Assumptions

Assume artificial lift engines are natural gas-burning reciprocating engines
Assume they are rich-burn engines (as in West Tavaputs EIS AQTSD) for purpose of AP-42 emission factors

VOC/THC= 1.053
NMHC/TH(0.048 EPA Conversion Factors for Hydrocarbon Components
EPA 420-R-05-015, December 2005.
Assume average heat rate of 8000 Btu/hp-hr for conversion from lbs/MMBtu to g/hp-hr per AP-42

Equations

PM, GHG Emission Factor (g/hp-h Emis Factor from AP-42 (lb/MMBtu) * 1x10^{-6} MMBtu/Btu * 8000 Btu/(hp-hr) * 453.6 (g/lb)

Table A36: Artificial Lift Engine Emissions

Artificial Lift Engine Emissions Per Well

NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	HCHO	Benzene	Toluene	Ethyl Benzene	Xylene	n-Hexane	CO2	CH4	Units
1.10	0.0001	0.83	0.33	1.8E-02	1.8E-02	8.7E-03	9.0E-03	1.9E-02	1.4E-03	5.1E-04	2.3E-05	1.8E-04	0.0E+00	1.0E+02	2.1E-01	tons/well
0.2522	0.0000	0.1892	0.0745	0.0040	0.0040	0.0020	0.0021	4.3E-03	3.3E-04	1.2E-04	5.2E-06	4.1E-05	0.0E+00	2.3E+01	4.8E-02	lbs/hr

Artificial Lift Engine Equipment Utilization

Equipment Type	# Units	Time/Unit (hours)	HP	Load
Lift Engine	1	8760	40	0.65

Average load and horsepower estimates derived from WRAP Phase III Emission Inventory survey of Uinta Basin Producers (Bar-Ilan et al., 2008)

Emission Factors for Artificial Lift Engines (g/hp-hr)

NOx[3]	SO_2[1]	CO[3]	VOC[3]	PM10[2]	PM2.5[2]	PM_filt[2]	PM_cond[2]	HCHO[2]	Benzene[2]	Toluene[2]	Ethyl Benzene[2]	Xylene[2]	n-Hexane[2]	CO2[2]	CH4[2]
4.4	0.0005	3.3	1.3	0.0345	0.0345	0.0345	0.0360	0.0743904	0.005734	0.002025	8.99942E-05	0.000708	0	399.168	0.834624

[1] Emission factors from (Pollack et al. 2006 Table 2-9)
[2] Emission factors from AP-42 Table 3.2-3, Uncontrolled Emission Factors for 4-stroke Rich-Burn Engines
[3] Emission factors from WRAP Phase III Emission Inventory survey of Uinta Basin Producers (Friesen et al. 2008) for typical pumpjack (Ajax 40 HP engine)

AP-42 assumption is all PM considered <10 microns in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).

Emissions (tpy)

NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	HCHO	Benzene	Toluene	Ethyl Benzene	Xylene	n-Hexane	CO2	CH4
1.10	0.0001	0.83	0.33	0.0177	0.0177	0.0087	0.0090	1.9E-02	1.4E-03	5.1E-04	2.3E-05	1.8E-04	0.00	1.0E+02	2.1E-01

Emissions (lbs/hr)

NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	HCHO	Benzene	Toluene	Ethyl Benzene	Xylene	n-Hexane	CO2	CH4
0.2522	0.0000	0.1892	0.0745	0.0040	0.0040	0.0020	0.0021	0.0043	0.0003	0.0001	0.0000	0.0000	0.0000	22.8800	0.0478

Table A37: Tank Working/Breathing Losses

Assumptions
No combustion units are on the tanks
Produced water is collected at the storage tanks
No heaters on the produced water tanks
Did not have flash gas composition, so used Flash Gas Composition for Typical Oil
Well from WRAP Phase III Uinta Basin Producers Survey
Grand Junction, CO was the nearest city to Ashley NF in the EPA Tanks program.

Each well site has two 400 barrel crude oil tanks
Tanks have 12 ' diameter, 20 ' high, and average liquid height assumed to be 10 feet
Used EPA TANKS 4.09 D to calculate the tank breathing and working loss emissions
Nearest City is Grand Junction CO
Assumed tank to be painted white, and shell to be in good condition, tank is heated
Assumed single component liquid composed only of crude oil (RVP 5), bulk temperature=50F
Operator expects total field production of 4000 bbl/day,
so if 400 wells, each well produces 10 bbls/day, 5bbl going to each tank at the well site

Operators predict 1 loadout every 8 days (see traffic worksheet)

Information from Operators
Assuming all 400 wells are productive, projected crude oil production would be about 4,000 bbls per day;
Each well would have two (2) 400 barrel crude oil tanks. These tanks are 12’ in diameter and 20’ in height.
Water production rate would be about 3 bbls per day. Breathing and working loss emission factors are unknown.
At each well site, there are two crude oil tanks. Each is equipped with a heater rated at 500,000 btu/hr.
They are Natco units. Hours of operation is about 2,500 per year. No combustion units are anticipated on these tanks.
There are no heaters on the produced water tanks.

Table A38: Tank Working/Breathing Emissions

Tank W/B Loss Emissions per Well									
Units	**VOC**	**Benzene**	**Toluene**	**Ethyl-Benzene**	**Xylenes**	**n-Hexane**	**HCHO**	**CO2**	**CH4**
tons/well	0.73	0.00332	0.05211	0.00461	0.03077	0.01305	0.00000	0.00007	0.00037
lbs/hr	0.167	0.001	0.012	0.001	0.007	0.003	0.000	0.000	0.000

Each well site has two 400 barrel crude oil tanks
Tanks have 12 ' diameter, 20 ' high, and average liquid height assumed to be 10 feet
Used EPA TANKS 4.09 D to calculate the tank breathing and working loss emissions
Nearest City is Grand Junction CO
Assumed tank to be painted white, and shell to be in good condition, tank is heated
Assumed single component liquid composed only of crude oil (RVP 5), bulk temperature=50F
Operator expects total field production of 4000 bbl/day,
so if 400 wells, each well produces 10 bbls/day, 5bbl going to each tank at the well site

Operators predict 1 loadout every 8 days
45 Loadouts per year
40 Barrels per tank per loadout

Conclude that all produced oil will be loaded out so calculate throughput as

Net throughput per year = 5 (bbl/day) * 365 (days/year) * 42 (gallons/bbl) 76650 gallons/year-tank

TANKS Results

	Losses(lbs)				Emissions
Components	Working Loss	Breathing Loss	Total Emissions	Units	(tpy)
Crude oil (RVP 5)	161.21	571.77	732.98	2	0.73

Emissions (tons/year per well site)

VOC	Benzene	Toluene	Ethyl-benzene	Xylenes	n-hexane	HCHO	CO2	CH4
0.7308	0.0033	0.0521	0.0046	0.0308	0.0130	0	7.3E-05	3.7E-04

Flash Gas Composition for Typical Oil Well from WRAP Phase III Uinta Basin Producers Survey

HCHO	0.00%	0
Benzene	0.45%	0.0045
Toluene	7.13%	0.0713
Ethylbenzene	0.63%	0.0063
Xylene	4.21%	0.0421
n-hexane	1.79%	0.0179
VOC fraction	99.70%	0.997
CO2	0.01%	0.0001
CH4	0.05%	0.0005

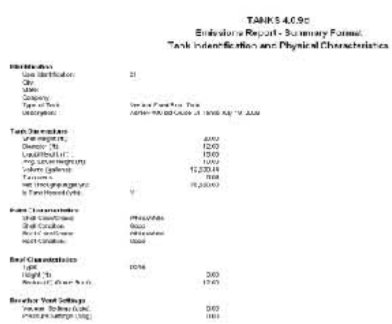


Table A39: Flashing Emissions

Flashing Emissions per well														
NOx	**SO2**	**CO**	**VOC**	**PM10**	**PM2.5**	**HCHO**	**Benzene**	**Toluene**	**hyl-Benze**	**Xylenes**	**n-Hexane**	**CO2**	**CH4**	**Units**
0.000	0.000	0.000	5.820	0.000	0.000	0.000	0.026	0.415	0.037	0.245	0.104	0.000582	0.002910136	tons/well
0	0	0	1.33	0	0	0	0.006	0.095	0.008	0.056	0.024	0.000	0.001	lbs/hr

Flashing Emissions per Tank (tpy)--Note Two Tanks per well

NOx	SO2	CO	VOC	PM10	PM2.5	HCHO	Benzene	Toluene	thyl-Benzer	Xylenes	n-Hexane	CO2	CH4
0	0	0	2.9	0	0	0.0	0.013	0.208	0.018	0.123	0.052	0.00029	0.00146

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

Spreadsheet from the Kansas DHE

INPUTS:

			Value from:	**CONSTRAINTS:**				
Stock Tank API Gravity	30	**API**	Operators[1]	**16**	**>API>**	**58**	°API	ok
Separator Pressure (psig)	150	**P**	WTP[2]	**50**	**>P+Patm>**	**5250**	**(psia)**	ok
Separator Temperature (°F)	105	**Ti**	WTP	**70**	**> Ti >**	**295**	**(°F)**	ok
Separator Gas Gravity at Initail Condition	0.9	**SGi**	KDHE[4]	**0.56**	**>SGi>**	**1.18**	**MW/28.97**	ok
Stock Tank Barrels of Oil per day (BOPD)	5	**Q**	Operators	**None**	**> Q >**	**None**	**(BOPD)**	ok
Stock Tank Gas Molecular Weight	49	**MW**	KDHE	**18**	**>MW>**	**125**	**lb/lb-mole**	ok
Fraction VOC (C3+) of Stock Tank Gas	0.997	**VOC**	WRAP III[3]	**0.5**	**>Voc>**	**1.00**	**Fraction**	ok
Atmospheric Pressure (psia)	14.7	**Patm**	KDHE	**20**	**> Rs >**	**2070**	**(scf/STB)**	ok

[1]Value of parameter from Ashley Operators

[2]Value of parameter is from West Tavaputs EIS

[3]Value of parameter from WRAP Phase III Uinta Basin Survey typical oil well flash gas composition

[4]Value of parameter from KDHE default for use when actual value is unknown

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	**0.93**

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	**< 30**	**>= 30**	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	**25.13**	**scf/bbl**	***for P + Patm =***	***164.7***

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	**2.9**	**TPY**

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	**2.9**	**TPY**	***from "FLASHING" of oil from separator to tank press***

Determine HAPS using oil well flash gas composition from WRAP Phase III survey of Uinta Basin Producers Friesen et al. (2008)

Susan Kemball-Cook: For comparison, look at flash gas composition from WTP EIS

HAP	Percentage	VOC Fraction	HAPS Emissions (tpy)	VOC	WTP EIS VOC Fraction
Benzene	0.45%	0.0045	0.013		0.0056
Toluene	7.13%	0.0713	0.208		0.0031
Ethylbenze	0.63%	0.0063	0.018		0.0000
Xylene	4.21%	0.0421	0.123		0.0003
n-hexane	1.79%	0.0179	0.052		0.0238
HCHO	0.000	0.0	0.0		0.0000

GHG	Percentage	VOC Fraction	GHG Emissions (tpy)
CO2	0.01%	0.0001	0.00029
CH4	0.05%	0.0005	0.00146

Table A40: Compressor Station Assumptions

Assumptions

See below

PM emissions were not provided so used emissions factors from AP-42.

Used brake-specific fuel consumption for a 4-stroke, lean burn compressor engine is 0.008 MMBtu/hp-hr as was done in the Hell's Gulch/Hightower EA.

Assumed 75% load and compressor engine runs continuously

Information from Operators

Apart from compressors, the only production equipment that would be present in the field would be four triethylene glycol dehydrators, and four condensate tanks, co-located with the centralized compresso

Pump and other specific information are not available for the dehydrators. However, these units would be comparable to those found in our Brundage Canyon field in terms of throughput and emissions.

At those four stations, glycol rates average 0.917 gpm each.

Emission calculations from the four Brundage Canyon dehy units equate to an average of:

- § 14.7 tons per year of VOC emissions per dehy unit.
- § 2.7 tons per year of total HAP emissions per dehy unit.

Similarly, the condensate tanks at the four proposed centralized compressor stations would be expected to see similar throughput of condensate as we are seeing at the Brundage Canyon tanks.

Emission calculations from the four Brundage Canyon condensate tanks equate to an average of:

- § 43.8 tons per year of VOC emissions per site/tank.
- § 1.7 tons per year of total HAP emissions per site/tank.

These are 4 300 barrel condensate tanks

Table A41: Compressor Station Emissions

Emissions per Compressor Station Complex (tons/year)																
NOx	SO2	CO	VOC	PM10	PM2.5	HCHO	Benzene	Toluene	hyl-Benze	Xylenes	n-Hexane	PM_filt	PM_Cond	CO2	CH4	Units
28.2	0.00	29.7	66.7	0.656	0.656	3.80	1.20	0.88	0.03	0.35	1.81	0.005	0.651	7227.056	90.953	tons/well
6.45	0.00	6.79	15.23	0.15	0.15	0.87	0.27	0.20	0.01	0.08	0.41	0.00	0.15	1650.01	20.77	lbs/hr

Each of the four central compressor station has a 2500 HP compressor, a dehy unit, and a condensate tank
Operators have provided emissions estimates for the dehy units, engines, and condensate tanks.

Site	Source	Throughput	Glycol Rates	Actual Facility Emissions (tons/year)														
			(actual)	NOx	CO	VOC	Benzene	Toluene	thylbenzen	Xylene	n-Hexane	Formaldehyde	Total HAP	PM10[5]	PM2.5[5]	CO2	CH4
Section 21	DEHY	2.8MMscfd	0.167 gpm			3.9	0.3	0.3	0.0	0.1	0.2		0.9	NO DATA PROVIDED			
	COND TANKS[1]	1.4 BCPD				36.7	0.1	0.1	0.0	0.2	0.6		1.0				
	ENGINES			19.4	15.5	4.6						1.7	1.7				
	TOTAL			19.4	15.5	45.1	0.4	0.4	0.0	0.3	0.8	1.7	3.6				
Section 7	DEHY	1.8MMscfd	0.917 gpm			12.9	0.8	0.2	0.0	0.1	0.4		1.5				
	COND TANKS[2]	5.4 BCPD				75.3	0.3	0.3	0.0	0.2	3.3		4.1				
	ENGINES			27.1	25.6	7.7						3.2	3.2				
	TOTAL			27.1	25.6	95.8	1.0	0.5	0.0	0.3	3.8	3.2	8.8				
Section 23	DEHY	4.8MMscfd	0.917 gpm			18.7	1.4	1.2	0.1	0.3	0.7		3.7				
	COND TANKS[3]	1.3 BCPD				3.6	0.0	0.0	0.0	0.0	0.1		0.1				
	ENGINES			34.8	44.3	11.6						6.0	6.0				
	TOTAL			34.8	44.3	33.8	1.4	1.2	0.1	0.3	0.8	6.0	9.8				
Section 22	DEHY	7.2MMscfd	0.917 gpm			23.3	1.9	1.4	0.1	0.5	0.8		4.7				
	COND TANKS[4]	8.0 BCPD				59.5	0.1	0.0	0.0	0.0	1.0		1.1				
	ENGINES			31.7	33.6	9.4						4.3	4.3				
	TOTAL			31.7	33.6	92.1	1.9	1.4	0.1	0.5	1.8	4.3	10.1				

Notes
[1] Sample Dated 4/21/06
[2] Average of samples from Section 21,23,22
[3] Average of Samples Dated 4/21/06 and 3/3/06
[4] Sample Dated 4/21/06

	NOx	CO	VOC	Benzene	Toluene	thylbenzen	Xylene	n-Hexane	Formaldehyde	Total HAP
Total Average	28.24	29.73	66.72	1.20	0.88	0.03	0.35	1.81	3.80	8.08
									0.95	2.02
Dehy avg	0.0	0.0	14.7	1.1	0.8	0.0	0.2	0.5	0.0	2.7
Tank avg			43.7	0.1	0.1	0.0	0.1	1.3		1.6
Engine Avg	28.2	29.7	8.3	0.0	0.0	0.0	0.0	0.0	3.8	3.8

Operators did not supply PM or GHG emissions. Used emission factors from AP-42 Table 3.2-2: Uncontrolled 4-stroke lean burn engines.
Assumed 8000 Btu/hp-hr heat input

Compressor Engine Utilization

Equipment Type	# Units	Time/Unit (hours)	HP	Load
Compressor Engine	1	8760	2500	0.75

Emissions factors (g/hp-hr)

Equipment	PM10	PM2.5	PM_filt	PM_cond	CO2	CH4
Compressor Engine			0.00027978	0.03596141	399.168	4.536

From AP-42 footnote j to Table 3.2-2,
PM considered <1 micron in aerodynamic diameter. Therefore, for filterable PM emissions,
PM10(filterable) = PM2.5(filterable).

Dehydration Unit GHG Emissions Estimate

Assume no glycol-assisted pump emissions, since do not
have information regardign details of dehy units. Emission factors
from API (2004).

Average throughput through the 4 dehy units = 4.15 MMscfd

Emission factor for CH4 for production industry segment = .0052869 tonnes/MMscf

CH4 Emissions = $\frac{(0.0052869 \text{ tonnes CH4})}{\text{1e6 scf gas}} \times \frac{(4.15 \times \text{1e6 scf gas})}{\text{day}} \times \frac{2204.62 \text{ lb}}{\text{tonne}} \times \frac{1 \text{ ton}}{2000 \text{ lb}} \times \frac{365 \text{ days} \times (.87/.87)}{\text{year}}$

CH4 Emissions = 8.827664199 tons/year

Note that the API calculation assumes that the mole fraction of CH4 is .87, which
is identical to the mole fraction in the Ashley gas composition provided by the Operators
CO2 fraction is 0.006349101 (ratio of CO2/CH4 in gas composition analysis)

CO2 emission factor = 0.056047727 tons/year

1 Metric tonnes = 1000 kg = 2204.62 lb.

Table A42: Fugitive Emissions

VOC	Benzene	Toluene	Ethyl-Benzene	Xylene	n-Hexane	HCHO	CO2	CH4	Units
0.725	0.000690	0.001646	0.000361	0.000773	0.002213	0	0.009012	1.806955	tons/well
0.1655	0.0002	0.0004	0.0001	0.0002	0.0005	0.0000	0.0021	0.4125	lbs/hr

Wells per pad= 1

API Gravity is 30 per Operators oil analysis

THC Emission Factor (lb/day/component)

Well Equipment Component	Gas	Light Oil >20º API	Heavy Oil <20º API
Connector	0.011	0.011	0.0004
Flanges	0.021	0.0058	0.000021
Open Ended Lines	0.11	0.074	0.0074
Valve	0.24	0.13	0.00044
Other	0.47	0.4	0.0017
Pump	0.13	0.69	n/a

Emission factors from WDEQ (2007) "Oil and Gas Production Facilities Chapter 6, Section 2, Permitting Guidance", p. 71
Do not calculate fugitives from pipelines containing only water
"Other" category includes compressor seals, pressure relief valves, diaphragms, drains, dump arms, hatches, intruments, meters, polished rods and vents

Well component counts from typical oil well counts from Combined Results of Survey of Uinta Basin producers
performed for the WRAP Phase III Emission Inventory (Friesen et al., 2008)

Fugitive Emissions from Well Site Equipment Leaks

Well Equipment Component	Total per Pad	Quantity/well	THC (lbs/day)	VOC (lbs/day)	Benzene (lbs/day)	Toluene (lbs/day)	Ethyl-Benzene (lbs/day)	Xylenes (lbs/day)	n-hexane (lbs/day)	CO2 (lbs/day)	CH4 (lbs/day)
Connector-gas line	55	55	0.605	0.095636029	0.000105399	5.91712E-05	3.08183E-06	1.35601E-05	0.0019151	0.007798268	0.44772055
Connector-oil line	55	55	0.605	0.17666	0.00016335	0.00045375	0.00010285	0.0002178	0	0	0.370865
Flanges-gas line	6	6	0.126	0.019917586	2.19508E-05	1.23233E-05	6.41836E-07	2.82408E-06	0.0003988	0.001624102	0.09324428
Flanges-oil line	0	0	0	0	0	0	0	0	0	0	0
Open Ended Gas Lines	2	2	0.22	0.034776738	3.83268E-05	2.15168E-05	1.12067E-06	4.93093E-06	0.0006964	0.002835734	0.162807473
Open Ended Oil Lines	3	3	0.222	0.064824	0.00005994	0.0001665	0.00003774	0.00007992	0	0	0.136086
Valve-gas line	12	12	2.88	0.455259113	0.000501732	0.000281674	1.46705E-05	6.45504E-05	0.0091163	0.037122333	2.131297823
Valve-oil line	20	20	2.6	0.7592	0.000702	0.00195	0.000442	0.000936	0		1.5938
Other gas line	0	0	0	0	0	0	0	0	0	0	0
Other oil line	3	3	1.2	0.3504	0.000324	0.0009	0.000204	0.000432	0		0.7356
Pump gas line	0	0	0	0	0	0	0	0	0	0	0
Pump oil line	10	10	6.9	2.0148	0.001863	0.005175	0.001173	0.002484	0	0	4.2297
Total (lbs/day)			15.36	3.97	0.0038	0.0090	0.0020	0.0042	0.0121	0.0494	9.9011
Total (tpy)			2.80	0.72	0.00	0.0016	0.000361	0.000773	0.002213	0.009012	1.806955

Where valve is in a pipe that carries the combined oil/gas/water stream from the well, treat as a gas pipeline to be conservative
For gas, use the gas composition analysis provided by the Operators. For oil, use table for light crude from WDEQ (2007), p. 71.

Speciated Fugitive Emission Factors (estimated weight fractions of THC emissions in each category) .									
	C6+		Methane	VOC	Benzene	Toluene	Ethyl-Benzene	Xylenes	n-hexane
heavy crude	0.0243		0.942	0.03	0.00935	0.00344	0.00051	0.00372	0
light crude	0.00752		0.613	0.292	0.00027	0.00075	0.00017	0.00036	0
gas production	0.00338		0.740033966	0.158076081	0.000174213	9.78036E-05	5.09394E-06	2.24133E-05	0.0031654

Table A43: Production Traffic Assumptions

Assumptions

Data assumed representative of project area from Western Regional Climate Center for Duchesne, UT (data source nearest project area). Mean for data from 1928-2007 is
Measurable precip (>0.01") at Duchesne, UT 62 days/year
http://www.wrcc.dri.edu/htmlfiles/ut/ut.01.html

Emission factors taken from the Moxa Arch TSD (BLM, 2007)
50% PM control efficiency from watering unpaved surfaces

Information from Operators
Trip distance (off of pavement) will average about 10 miles each way for well, pipeline and compressor construction.
See attached Excel spreadsheet for number and type of trips anticipated for each phase of well development through production.
(attached Excel spreadsheet referenced above is included here as the Truck Traffic Worksheet)

Equations

$$\text{Emissions (tons/year-well)} = \frac{\text{Emission factor (g/mile)} * \text{\# Trips} * \text{Trip Distance (miles)}}{453.5\ \text{(g/lb)} * 2000\ \text{(lbs/ton)}}$$

$$\text{Emissions [lb/VMT]} = \frac{k(s/12)^a(W/3}{(M/0.2)^c} \frac{*(365-P)}{365} *\text{(Control Efficiency)}$$

$$SO_2\ \text{Emission Factor (g/mile)} = \frac{\text{Fuel Density (lbs/gallon)} * \text{(453.6 g/lb)} * \text{Fuel Sulfur Content} * 2}{\text{Vehicle Fuel Efficiency (miles/gallon)}}$$

Diesel fuel sulfur content assumed to be 0.05% per operators

Diesel fuel density assumed to be 7.08 lbs/gallon (As in West Tavaputs EIS)
Heavy truck fuel efficiency = 10 miles/gallon (As in West Tavaputs EIS)
Light truck fuel efficiency = 15 miles/gallon (As in West Tavaputs EIS)
Factor of 2 is the weight ratio of SO_2 to sulfur

Truck Loadout Emissions

$$\text{Emissions (tpy)} = \frac{1.69\ \text{lb}}{1000\ \text{gallon}} \frac{42\ \text{gallons}}{\text{bbl}} \frac{80\ \text{bbl}}{\text{loadout}} \frac{\text{ton}}{2000\ \text{lb}} \frac{45\ \text{loadouts}}{\text{year}}$$

Table A44: Production Traffic Emissions

Production Traffic Emissions Per Well								
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	Units
0.01	0.002	0.10	0.01	1.07	0.109	0.001	0.002	tpy
0.0029	0.0005	0.0225	0.0023	0.2447	0.0250	0.0002	0.0003	lbs/hr

Exhaust Emissions from Truck Traffic Associated with Production Phase

Emission Factors for Exhaust from Road Traffic

Vehicle	Emission Factors (g/mi)							
Type	Class	Model Year	NO_x	PM_{10} [b,c]	$PM_{2.5}$ [b,c]	SO_x [a]	CO	VOC
Light-Duty Gasoline Truck	LDGT2	1999+	0.79	0.10	0.08	0.21	10.15	0.63
Heavy-Duty Diesel Truck	HDDV	2001+	6.49	1.96	1.81	0.32	17.06	5.08

NOx, VOC, and CO Source: EPA, *AP-42*, Volume II, Appendix H-117, Table 3.1A.2 Light Duty Gasoline Powered Trucks II and Appendix H-259, Table 7.1.2 Heavy Duty Diesel Powered Vehicles (High Altitude; 50,000 mileage) (6/30/95).
[a] Method from MOBILE6.1 Particulate Emission Factor Model Technical Description EPA420-R-02-012 March 2002, equation 3.7
[b] Including tire and brake wear emissions.
[c] From Moxa Arch TSD, taken from BLM, 2003, APP_A21, table 1.1.2.2, estimated using EPA PART5 Model (1995)

Destination	Vehicle Type	Vehicle Class	Round Trip Distance (mi)	# of Round Trips per Well Pad or per Station	Miles Traveled per Well Pad or per	Emissions (tpy/well pad) NO_x	PM_{10}	$PM_{2.5}$	SO_2	CO	VOC	PM_filt	PM_Cond
Well Pad	Tanker Truck	HDDV	20	45	900	0.006	0.002	0.002	0.000	0.017	0.005	0.001	0.001
	Pickup Trucks	LDGT2	20	365	7300	0.006	0.001	0.001	0.002	0.082	0.005	0.000	0.000

Fugitive Dust Emissions Associated with Production Traffic To Well

Source for Data for Constants: EPA (1995), AP-42, Section 13.2.2 Unpaved Roads (9/98). Table 13.2.2-2.

$$E\ [\text{lb/VMT}] = \frac{k(s/12)^a (W/3)^d}{(M/0.2)^c} * \frac{(365-P)}{365} * (\text{Control Efficiency})$$

Constant	PM_{10}	$PM_{2.5}$
k	1.8	0.18
a	1	1
d	0.5	0.5
c	0.2	0.2

Variable Description	Assumed Value	Reference
E = size-specific emission factor (lb/VMT)		
s = surface material silt content (%)	5.1	EPA, *AP-42*, Volume I, Section 13.2.2 Unpaved Roads (9/98)
W = mean vehicle weight (tons)	37.5	Assume an oil tanker truck of 75,000 lb (BLM,2008)
W = mean vehicle weight (tons)	3.5	Pickup truck weighs 7000 lbs
M = surface material moisture content (%)	2.4	AP-42 Table 11.9-3 as in Jonah EIS
Control efficiency for watering (%) =	50	EPA, *Control of Open Fugitive Dust Sources*, Section 5.3.1 Watering of Unpaved Surfaces (1988)
P = Precipitation Days (>0.01" rainfall)	62	Precipitation days at Duchesne, UT from NCDC climatology

Fugitive Dust Emissions Estimation for Oil Tanker Road Traffic: Long-term Production

Activity	Vehicle Type	Av. Vehicle Weight (lb)	# of Visits per Year	Total # of Round Trips	Round Trip Distance (mi)	Total Miles Traveled	PM_{10} Em. Factor (lb/VMT)	PM_{10} Emissions (tpy/well)	PM2.5 Em. Factor (lb/VMT)	PM2.5 Emissions (tpy/well)
Travel to well	Light truck	7000	365	365	20	7300	0.21	0.8	0.02	0.1
Travel to Transport Oil	Oil Tanker	75,000	45	45	20	900	0.68	0.3	0.07	0.0
						Total		**1.1**		**0.1**

Table A45: Truck Loadout Emissions

Well Site Oil Tank Loadout Emissions									
VOC	**Benzene**	**Toluene**	**Ethyl-Benzene**	**Xylene**	**n-Hexane**	**HCHO**	**CO2**	**CH4**	**Units**
0.13	0.000580	0.009088	0.000804	0.005366	0.002275	0	1.274E-05	6.372E-05	tons/year
0.0291	0.0001	0.0021	0.0002	0.0012	0.00052	0.0000	2.9E-06	1.5E-05	lbs/hr

VOC Losses from Truck Loading of Oil from Tanks at Well Pad
Method from Wyoming Permitting Guidance for Oil and Gas Production Facilities
Wyoming DEQ, August, 2007, Chapter 6, Section 2, p.69 for Crude Oil, RVP 5
After AP-42, Section 5.2.1

Emissions VOC (tpy) = $\frac{\text{Loading Loss (lbs/1000 gal) * truck load rate (bbl/year) * 42 (gal/bbl)}}{\text{2000 (lbs/ton)}}$

Loading losses determined using AP-42 Section 5.2.2.1.1 Equation 1

LL =12.46 x S x P x M/T

LL=Loading Loss in (lbs/1000gallons)
S= Saturation Factor
P = true vapor pressure of liquid loaded (psia)
M = molecular weight of tank vapors (lb/(lb-mol))
T = temperature of bulk liquid loaded (R=F+460)

Calculation done For Petroleum Liquid Crude Oil of RVP 5.

Assume submerged loading (i.e. truck is designed so that liquids enter the tank bottom to avoid splashing)
Assume temperature of 50F, and truck has a capacity of 90 bbl, takes 1 hour to load

According to Sample Calculations for Oil Loadout from Wyoming Permitting Guidance, (WDEQ, 2007)

S = 0.6 (AP-42 Table 5.2-1 Submerged loading, dedicated Normal Service)
P = 2.3
M = 50

LL = $\frac{\text{12.46 x 0.6 x 2.3 (psia) x 50 (lb/lb-mol)}}{\text{50ºF + 460}}$ = 1.69 lb/1000 gallons

Operators predict 1 loadout every 8 days 45 loadouts/year
Production estimated to be 10 barrels per day per well, so each loadout takes 80 barrels

Truck Loadout Emissions

VOC Emissions (tpy) = $\frac{\text{1.69 (lb) * 42 (gal/bbl) * 80 (bbl/loadout) * 45 (loadouts/yr)}}{\text{1000 (gal) * 2000 (lbs/ton)}}$ = 0.13 tpy

Determine concentration of HAPS by scaling the HAPS emissions to the VOC emissions based on an estimate of the composition of tank condensate. Tank condensate composition not supplied by Operators,
so determine HAPS using oil well flash gas composition from WRAP Phase III survey of Uinta Basin Producers
Friesen et al. (2008)

Ashley Tank Loadout Emissions (tpy)								
VOC	Benzene	Toluene	Ethyl-Benzene	Xylenes	n-Hexane	HCHO	CO2	CH4
0.13	0.0006	0.0091	0.0008	0.0054	0.0023	0	1.274E-05	6.372E-05

HAP	Percentage	VOC Fraction
Benzene	0.45%	0.0045
Toluene	7.13%	0.0713
Ethylbenzene	0.63%	0.0063
Xylene	4.21%	0.0421
n-hexane	1.79%	0.0179
HCHO	0.00%	0.0000
CO2	0.01%	0.0001
CH4	0.05%	0.0005

Table A46: Peak Year Emissions Summary by Category and Greenhouse Gas Summary

Construction (Well)

Construction Emissions per Well (tons/well)																			
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	thyl-Benzer	Xylene	n-Hexane	CO2	CH4
1.62	0.02	0.34	0.06	1.68	0.22	0.02	0.03	1.47	0.17	0.02	0.03	0.00	0.00	0.00	0.00	0.00	0.00	131	0.07

Construction (Cmprsr Station)

Construction Emissions per Compressor Station (tons/well)																			
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	thyl-Benzer	Xylene	n-Hexane	CO2	CH4
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Production (Well)

Production Emissions per Well (tons/well)																			
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	thyl-Benzer	Xylene	n-Hexane	CO2	CH4
1.22	0.00	1.02	7.75	1.10	0.14	0.01	0.02	0.96	0.11	0.01	0.02	0.02	0.03	0.48	0.04	0.28	0.12	229	2.02

Production (Cmprsr Station)

Production Emissions per Compressor Station (tons/well)																			
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	thyl-Benzer	Xylene	n-Hexane	CO2	CH4
28.24	0.00	29.73	66.72	0.66	0.66	0.01	0.65	0.00	0.00	5.07E-03	6.51E-01	3.80	1.20	0.88	0.03	0.35	1.81	7227	91

Peak Year

20 year life of project: assume development proceeds at an even pace of 20 wells drilled per year.

In last year of drilling, production emissions are at max because all compressor stations and wells are operating. No compressor station construction emissions.

Emissions = (Production Emissions/well) x (number of wells) + (compressor emissions)x(# compressors) + (construction emissions)*(# wells built)

Emissions = Production Emissions x 380 + Compressor Emissions x 4 + Construction Emissions x 20

Total Project Emissions in Final (Peak) Year of Project																			
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	thyl-Benzer	Xylene	n-Hexane	CO2	CH4
611	1.2	512	3212	453	58.3	4.8	9.5	395.0	44.0	4.8	9.5	22.3	17.1	185.3	16.3	109	53.4	118503	1134

Total Per Well Average Emissions in Final (Peak) Year of Project																			
NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	thyl-Benzer	Xylene	n-Hexane	CO2	CH4
1.24	0.00295	0.98	7.36	1.13	0.14	0.01	0.02	0.99	0.11	0.01	0.02	0.02	0.03	0.45	0.04	0.27	0.12	224	1.92

Emissions by Category (tons/(year-well))

Category	NOx	SO2	CO	VOC	PM10	PM2.5	PM_filt	PM_cond	PMC	PMF	EC	SOA	HCHO	Benzene	Toluene	thyl-Benzer	Xylene	n-Hexane	CO2	CH4
Pad Construction	0.21	1.18E-04	7.75E-02	0.02	0.01	0.01	4.05E-03	6.89E-03	3.38E-04	0.00E+00	4.05E-03	6.89E-03	-	-	-	-	-	-	13	0
Well/Pipe Const FugDust	0.00	0.00	0.00	0.00	0.03	0.01	0.00	0.00	0.01	0.01	0.00	0.00	-	-	-	-	-	-	-	-
Pad Construction Traffic	7.11E-04	6.61E-05	3.29E-03	5.59E-04	0.04	4.48E-03	6.39E-05	1.09E-04	0.04	0.00	6.39E-05	1.09E-04	-	-	-	-	-	-	-	-
Wind Erosion	0.00	0.00	0.00	0.00	0.04	0.0000	0.00	0.00	0.04	0.00	0.00	0.00	-	-	-	-	-	-	-	-
Pipeline Construction	1.82E-03	0.00	1.07E-03	2.82E-04	0.00	2.31E-04	8.54E-05	1.45E-04	7.14E-06	0.00	8.54E-05	1.45E-04	-	-	-	-	-	-	0.15	0
Drilling	1.30	1.55E-02	0.1387	0.02	0.02	0.02	8.64E-03	1.47E-02	7.22E-04	0.00	8.64E-03	1.47E-02	-	-	-	-	-	-	107	0.07
Drilling Road Traffic	0.01	1.07E-03	0.0543	0.0115	0.79	0.08	1.41E-03	2.40E-03	0.71	0.08	1.41E-03	2.40E-03	-	-	-	-	-	-	-	-
Completion	0.08	0.00	0.0178	3.66E-03	0.00	0.00	1.37E-03	2.33E-03	1.14E-04	0.00	1.37E-03	2.33E-03	-	-	-	-	-	-	10	0
Completion Road Traffic	0.01	0.00	0.0400	9.22E-03	0.61	0.06	1.15E-03	2.12E-03	0.55	0.06	1.15E-03	2.12E-03	-	-	-	-	-	-	-	-
Install Prod Eq. Traffic	2.25E-03	1.65E-04	8.40E-03	1.76E-03	0.12	0.01	2.15E-04	3.66E-04	0.11	0.01	2.15E-04	3.66E-04	-	-	-	-	-	-	-	-
Tank W/B Losses	0.00	0.00	0.0000	0.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.03	0.01	7.31E-05	3.65E-04
Heaters	0.11	0.00	9.01E-02	5.90E-03	0.01	8.15E-03	2.04E-03	6.11E-03	0.00	0.00	2.04E-03	6.11E-03	8.04E-05	2.25E-06	3.65E-06	0.00	0.00	0.00E+00	129	2.47E-03
Artificial Lift Engines	1.10	0.00	0.83	0.33	0.02	0.02	8.65E-03	9.03E-03	0.00	0.00	8.65E-03	9.03E-03	0.02	1.44E-03	5.08E-04	2.26E-05	1.78E-04	0.00E+00	100	0.2095
Flashing	0.00	0.00	0.00	5.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.42	0.04	0.25	0.10	5.82E-04	2.91E-03
Fugitives	0.00	0.00	0.00	0.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.90E-04	1.65E-03	3.61E-04	7.73E-04	2.21E-03	9.01E-03	1.81
Production Traffic	0.01	0.00	0.10	0.01	1.07	0.11	8.88E-04	1.51E-03	0.96	0.11	8.88E-04	1.51E-03	-	-	-	-	-	-	-	-
Tank Loadout	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.80E-04	9.09E-03	8.04E-04	5.37E-03	2.28E-03	1.27E-05	6.37E-05
Total Construction	1.62	0.02	0.34	0.06	1.68	0.22	0.02	0.03	1.47	0.17	0.02	0.03	0.00	0.00	0.00	0.00	0.00	0.00	131	0.07
Total Production	1.22	0.00	1.02	7.75	1.10	0.14	0.01	0.02	0.96	0.11	0.01	0.02	0.02	0.03	0.48	0.04	0.28	0.12	229	2.02
Total peak yr proj well emis	498	1.2	393	2945	451	56	4.7	6.9	395	44	4.7	6.9	7.1	12.4	182	16	107	46	89595	770

Peak Year Greenhouse Gas Emissions in CO2 Equivalents

		GWP	CO2 Equivalents
Total CO2	89595.3	1	89595.26
Total CH4	769.8	21	16165.37
Total GHG			105760.6 CO2 Equivalents

GWP from IPCC (1995

2005 Estimated Wyoming CO2 Equivalent GHG Emissions =	5.60E+07 metric tons/year	
2005 Estimated Colorado CO2 and CO2 equivalent emissions =	1.18E+08 metric tons/year	
2006 Estimated US GHG CO2 equivalent emissions	7.08E+09 metric tons/year	
2000 Estimated Utah GHG CO2 Equivalent emissions	6.88E+07 metric tons/year	
0.0015% Ashley percentage of GHG of US 2006 emissions	EIA (2006) Emissions of Greenhouse Gases in the United States 2006	
0.09% Ashley percentage of 2006 CO GHG emissions	Hell's Gulch EIS	
0.15% Ashley percentage of 2005 UT GHG emissions	UDEQ "Final Utah Greenhouse Gas Inventory and Reference Case Projections 1990-2020"	
0.19% Ashley percentage of 2005 WY GHG emissions		

Table A47: Greenhouse Gas Comparison

	CO_2 Equivalents (metric tons/year)	Ashley %
Ashley Project[1]	1.06E+05	100%
United States (2006)	7.08E+09	0.001%
Utah (2005)	6.88E+07	0.154%
Colorado (2005)	1.18E+08	0.090%
Wyoming (2005)	5.60E+07	0.189%

[1] Year of maximum emissions

APPENDIX B
Cumulative Emissions Inventory

B.1 STATE AGENCY-PERMITTED INDUSTRIAL SOURCE INVENTORY

B.1.1 State Air-Quality Regulatory Authority

An emission inventory of industrial sources within the Project's regional modeling domain was prepared for use in the cumulative air quality analysis. A list of permitted sources within the region of interest was generated through queries of databases maintained by the WDEQ-AQD, Utah DEQ, and the Colorado Department of Public Health and the Environment. The cumulative emission inventory for the Ashley CALPUFF modeling was based on the Moxa Arch Area Infill Gas Development Project (BLM, 2007) and Hiawatha Regional Energy Development Project (NRG, 2006b) Environmental Impact Statement emission inventories, which were expanded to include sources south of the Moxa Arch/Hiawatha modeling domains in Utah and Colorado and updated to include sources that were permitted between June 30, 2006 and December 31, 2007. The determination of sources to be included in the cumulative emission inventory was based on a set of criteria described below. These criteria were developed for the Moxa Arch/Hiawatha CALPUFF modeling emission inventories. The following criteria were the basis on which sources were included or excluded:

- Include sources permitted and operating January 1, 2001 – December 31, 2007.
- Include if permitted on or after July 1, 2006, but not yet operating.
- Exclude sources permitted and operating prior to January 1, 2001, sources listed but with permits cancelled or rescinded, and sources with no emissions of the pollutants of interest.

Other reasons for excluding a source were:

- Emissions decrease at a source that emitted less than 100 tons per year (tpy) of each criteria pollutant.
- Source is a production site with less than 3 tpy increase for each pollutant. All other production sites are assumed to be included in WOGCC, COGCC, UDNR-DOGM production estimates.
- Emissions increase is less than1 tpy for each individual pollutant (including VOC and HAPs). If any one pollutant has emissions greater than 1 tpy, the source was included.
- Oil and gas waiver with change less than 3 tpy total emissions including VOC and HAPs.
- Emissions decrease at a non-major source (including VOC and HAPs). A non-major source is defined to be one for which emissions of each individual pollutant is less than 100 tpy.
- Non-production site with less than 1 tpy increase in all criteria pollutants and VOCs and HAPs.
- Non-oil and gas sources operating under permit waivers were not inventoried due to their small contribution to the total emission inventory.

Excluded facilities and the reasons for exclusion were documented. The state databases were queried for active facilities with NSR Permit or Waiver Issue Date between 1/1/2001 and 12/31/2007 that emitted the pollutants of interest (CO, HAPs, Formaldehyde, VOC, NOx, SO_2, PM10, and $PM_{2.5}$). For all included sources, the following information was collected if available:

- Company
- Facility name
- Source classification
- Permit number
- Permit issue date
- Unique source ID numbers and SIC codes if available
- Site location (latitude/longitude, UTM easting and northing and zone, and/or section/township/range)
- Site elevation
- Permitted change in CO, HAPs, Formaldehyde, VOC, NOx, SO_2, PM10, and $PM_{2.5}$ emission rate by source during inventory period
- Stack exit parameters: height, temperature, velocity, diameter, and flow rate

The change in permitted emission limits occurring during the inventory period was obtained for the included sources.

For any modification to an included permitted source:

- The permitted increase or decrease was obtained from permit documents by locating a description of change or by recording both new and old permit limits.
- Emissions decreases were tracked for major sources only (>250 tpy).
- Emissions increases of less than 1 tpy were not tracked.

Where stack parameters were not supplied in the state inventories, default stack parameters based on the Atlantic Rim Technical Support Document, Appendix C, Table C7 were used. These parameters are shown in Table B1.1.1.

Table B1.1.1. Default Stack Parameters for cumulative emission inventory sources with missing stack parameter data.

Stack Height	Stack Height	Temperature	Exit Velocity
0.51 m	9.82 m	633.80 K	30.08 m/s

B.1.2 State-Specific Methodologies

The inventory area includes a portion of Wyoming, Colorado, and Utah. Due to the differences in data provided by each state, some minor differences in inventory procedures were necessary. The following are state-specific procedures used in the inventory.

Utah

All Utah permitted sources were assumed operational. No source category codes were provided in this inventory. Utah included state-permitted sources are shown in Table B4.1.1 and Utah excluded state-permitted sources are shown in Table B4.2.1.

Colorado

All permits issued through December 31, 2007 were conservatively assumed to be operational. All Colorado sources have a source category code. At the recommendation of the CDPHE, sources with codes indicating that their permits are expired, grandfathered, or cancelled were excluded from the inventory. Colorado included state-permitted sources are shown in Table B4.1.2 and Colorado excluded state-permitted sources are shown in Table B4.2.2.

Wyoming

Start-up dates were provided by WDEQ-AQD to determine the operating status of a facility. Due to the variation in start-up data, all facilities permitted within the inventory timeframe were assumed to be operational. No stack parameters or source classification codes were provided in this inventory, although a general category was given for each source. Wyoming included state-permitted sources are shown in Table B4.1.3 and Wyoming excluded state-permitted sources are shown in B4.2.3. Included RFFA sources are shown in Table B4.1.4. Note that Wyoming production sources with waivers and emitting more than 3 tpy were mistakenly excluded from the Moxa Arch/Hiawatha cumulative inventory and this error was rectified in the Ashley inventory.

B.2 RFD INVENTORY

In accordance with definitions agreed upon by BLM, EPA, WDEQ-AQD, and USDA Forest Service for use in EIS projects, RFD was defined as 1) the NEPA-authorized but not yet developed portions of NEPA projects and 2) not yet authorized NEPA projects for which air quality analyses were in progress and for which emissions had been quantified. RFD within the inventory area was compiled, including portions of Wyoming, Colorado, and Utah. BLM Emissions from RFD were summarized by project for all pollutants for which data was available. Projects that are fully developed were excluded from the inventory. A summary of RFD is included in Table 4.1.5.

B.3 NATURAL GAS AND OIL WELL AGENCY-PERMITTED SOURCES

Natural gas and oil well data were gathered by obtaining permitted well listings from state oil and gas permitting agencies including the Wyoming Oil and Gas Conservation Commission (WOGCC), the Colorado Oil and Gas Conservation Commission (COGCC), and the Utah Department of Natural Resources-Division of Oil, Gas, and Mining (UDNR-DOGM). Wells with permits issued between January 1, 2001 and December 31, 2007 were inventoried. An average emission rate per unit natural gas well of 0.2 tpy NOx was used. An average emission rate of 0.3 tpy NOx was obtained from WDEQ-AQD for oil wells (BLM, 2007). These representative emission rates were applied to calculate total NOx emissions per county. PM_{10}, $PM_{2.5}$, and SO_2 emissions were assumed to be negligible from oil and gas wells. All oil and gas agency-permitted well data are included in Table 4.1.6.

B.4 CUMULATIVE EMISSION INVENTORY TABLES

B.4.1 Tables of Included Sources

Table B4.1.1: Utah Included Permitted Industrial Sources
Table B4.1.2: Colorado Included Permitted Industrial Sources
Table B4.1.3: Wyoming Included Permitted Industrial Sources
Table B4.1.4: Wyoming Included RFFA Sources
Table B4.1.5: RFD Sources
Table B4.1.6: State Permitted Wells; Colorado, Wyoming, and Utah

B.4.2 Tables of Excluded Sources

Due to their large size, the following tables are not included in this document.

Table B4.2.1: Utah Included Permitted Industrial Sources
Table B4.2.2: Colorado Included Permitted Industrial Sources
Table B4.2.3: Wyoming Included Permitted Industrial Sources
Table B4.2.4: Wyoming Included RFFA Sources

Table B4.1.1: Utah Included Permitted Industrial Sources

County	Facility	Site ID	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)
Beaver	Circle Four Farms: Circle Four Feedmill	11440	-1379.32	-56.273	0.02	2.56	15.54	7.87	0.16	2.99	30.08
Beaver	Dairy Farmers of America: Cheese & Condensed Milk Processing Plant	13251	-1272.41	53.316	0.57	17.10	1.42	0.00	0.16	2.99	30.08
Beaver	Harborlite Corporation: Perlite Processing Plant	11733	-1379.832	-55.995	0.51	8.04	1.58	1.08	0.16	2.99	30.08
Beaver	Quality Crushing: Crushing and Screening Operations	12125	-1378.632	-74.739	0.18	2.26	0.69	0.37	0.16	2.99	30.08
Beaver	Smithfield BioEnergy LLC: Animal Waste Mitigation Plant - Methane Production	13330	-1389.992	-74.084	3.21	7.22	0.39	0.39	0.16	2.99	30.08
Beaver	Twin Mountain Rock Company: Twin Mountain Rock	11590	-1383.59	-47.868	2.04	19.65	28.49	5.23	0.16	2.99	30.08
	Beaver County Total				6.53	56.83	48.11	14.94			
Box Elder	Consolidated Paving & Concrete Inc.: Asphalt Plant	13096	-1171.166	45.637	2.71	30.17	15.36	0.00	0.16	2.99	30.08
Box Elder	Granite Construction Company: Wells Sand & Gravel Pit	12905	-1236.463	169.893	0.94	9.20	14.40	0.00	0.16	2.99	30.08
	Box Elder County Total				3.65	39.37	29.76	0.00			
Carbon	Andalex Resources Incorporated: Centennial Minesite	10082	-1163.438	55.208	0.36	5.25	3.52	1.09	0.16	2.99	30.08
Carbon	Andalex Resources Incorporated: Wildcat Loadout	10113	-1179.529	52.266	1.26	18.93	27.06	7.45	0.16	2.99	30.08
Carbon	Bill Barret Corporation: Dry Canyon Compressor Station	12948	-1115.385	56.719	0.27	31.16	4.34	4.34	0.16	2.99	30.08
Carbon	Bill Barret Corporation: Interplanetary Compressor Station	13284	-1126.17	57.24	0.05	16.30	1.57	0.00	0.16	2.99	30.08
Carbon	Bill Barrett - Rock Crushing	14002	-1113.417	56.949	0.07	1.00	0.26	0.18	0.16	2.99	30.08
Carbon	COVOL Engineered Fuels LLC: Wellington Coal Blending	12952	-1255.415	177.564	0.16	1.69	7.91	1.47	0.16	2.99	30.08
Carbon	Canyon Fuel Company LLC: Dug-Out Canyon Coal Mine	11634	-1151.946	48.653	2.80	24.27	14.59	2.44	0.16	2.99	30.08
Carbon	Canyon Fuel Company LLC: Skyline Mines	10092	-1203.602	59.315	1.99	31.74	4.41	0.00	0.16	2.99	30.08
Carbon	College of Eastern Utah: Central Heating Plant	10102	-1171.166	45.637	0.02	1.91	0.11	0.03	0.16	2.99	30.08
Carbon	DTE Utah Synfuels LLC: Agglomeration Facility - Coal Fines	11819	-1272.41	53.316	0.20	30.10	7.20	0.00	0.16	2.99	30.08
Carbon	ECDC Environmental LC: East Carbon Landfill	10107	-1145.042	32.802	2.74	27.91	29.75	10.67	0.16	2.99	30.08
Carbon	Hidden Splendor Resources Incorporated: Horizon Coal Mine	12399	-1190.621	58.338	0.34	5.11	1.76	0.51	0.16	2.99	30.08
Carbon	Musket Corporation: Helper Transloading Facility	14165	-1175.099	56.339	0.19	2.91	0.21	0.00	0.16	2.99	30.08
Carbon	Nelco Contractors Incorporated: Price Gravel Mining & Screening Plant	11334	-1159.878	44.477	0.19	2.66	3.33	1.52	0.16	2.99	30.08
Carbon	PacifiCorp: Carbon Power Plant	10081	-1174.538	59.367	1323.69	477.36	33.56	15.70	0.16	2.99	30.08
Carbon	Questar Pipeline Company: Oak Spring Turbine Compressor Station	12103	-1176.215	52.502	0.41	28.85	3.16	3.16	0.16	2.99	30.08
Carbon	Savage Industries Incorporated: Savage Coal Terminal	11793	-1169.873	35.2	2.96	44.99	62.23	17.54	0.16	2.99	30.08
Carbon	Staker & Parson Companies: Wellington Asphalt Plant	10979	-1166.034	37.211	3.49	8.84	0.79	0.29	0.16	2.99	30.08
Carbon	Sunnyside Cogeneration Associates: Sunnyside Cogeneration Facility	10096	-1136.951	33.903	448.59	458.70	91.95	52.01	0.16	2.99	30.08
Carbon	Westridge Resources Inc.: West Ridge Mine	12167	-1140.481	41.874	0.23	3.31	3.89	1.16	0.16	2.99	30.08
	Carbon County Total				1790.01	1222.99	301.60	119.57			
Daggett	Questar Pipeline Company: Kastler/Marushack Compressor Station	11532	-1016.538	178.541	1.31	850.89	2.91	2.91	0.16	2.99	30.08
	Dagget County Total				1.31	850.89	2.91	2.91			
Davis	Allroc Products: Beck Street Sand and Gravel Pit	11592	-1242.791	192.921	1.30	1.82	2.88	0.00	0.16	2.99	30.08
Davis	Ashland Chemical Company: Chemical Distribution Center	10148	-1247.581	225.649	0.00	0.41	0.02	0.02	0.16	2.99	30.08
Davis	Bountiful City Light and Power: Power Plant	10120	-1239.276	199.783	0.53	12.15	0.20	0.20	0.16	2.99	30.08
Davis	Flying J Incorporated: Flying J Refinery (Big West Oil Co.)	10122	-1243.052	194.77	168.18	17.06	24.42	44.51	0.16	2.99	30.08
Davis	Foreland Refining Corporation: Asphalt Blowing Plant	12785	-1242.531	196.705	0.01	2.49	7.22	3.47	0.16	2.99	30.08
Davis	Hill Air Force Base: Main Base	10121	-1241.584	226.81	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Davis	Holly Refining & Marketing Company: Phillips Refinery	10123	-1240.756	199.735	0.00	0.00	0.00	9.96	0.16	2.99	30.08
Davis	KC Asphalt LLC: Hot Asphalt Storage Terminal	12469	-1241.463	198.829	0.02	2.31	0.00	0.00	0.16	2.99	30.08
Davis	Lakeview Rock Products: Thomas Pit	13141	-1242.52	194.183	0.25	3.67	1.86	0.65	0.16	2.99	30.08
Davis	Peak Asphalt LLC: Cowboy Asphalt Terminal	12145	-1242.487	196.889	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Davis	Pioneer Investments Corporation: Salt Lake Terminal Company	10133	-1241.636	197.62	0.00	6.17	0.00	0.00	0.16	2.99	30.08
Davis	Silver Eagle Refining - Woods Cross Inc.: Petroleum Products Refining	10124	-1241.799	198.052	1.30	85.21	3.05	2.89	0.16	2.99	30.08
Davis	Stericycle Incorporated: BFI Medical Waste Incinerator	10142	-1244.681	196.443	0.00	17.33	0.32	0.32	0.16	2.99	30.08
Davis	Utility Trailer Manufacturing Company: Trailer Manufacturing Facility	10156	-1247.064	225.095	0.45	38.77	0.97	0.97	0.16	2.99	30.08
Davis	Wasatch Integrated Waste Mgt District: County Landfill & Energy Recovery Facility (DCERF)	10129	-1240.76	224.887	30.36	280.80	27.32	11.31	0.16	2.99	30.08
	Davis County Total				202.41	468.20	68.26	74.30			
Duchesne	Burdick Paving Company: Madsen 4000 Asphalt Hot Plant #481	10221	-1097.81	109.933	0.16	0.85	2.59	0.80	0.16	2.99	30.08
Duchesne	Burdick Paving Company: Portable Equipment - Temporary Locations	11357	-1117.844	115.56	0.03	0.00	0.00	0.00	0.16	2.99	30.08
Duchesne	El Paso Field Operations Company: Altamont East Compressor Station	10209	-1112.413	120.506	0.02	0.00	0.00	0.00	0.16	2.99	30.08
Duchesne	El Paso Field Operations Company: Altamont Main Gas Processing Plant	10005	-1119.136	121.775	0.06	0.00	0.00	0.00	0.16	2.99	30.08
Duchesne	El Paso Field Operations Company: Altamont South Compressor Station	10211	-1129.518	113.719	0.06	18.12	0.18	0.18	0.16	2.99	30.08
Duchesne	El Paso Field Operations Company: Altamont West Compressor Station	10210	-1125.403	118.294	0.03	3.39	0.05	0.06	0.16	2.99	30.08
Duchesne	El Paso Field Operations Company: Bluebell Gas Plant	10219	-1098.393	121.595	0.10	178.24	1.24	1.24	0.16	2.99	30.08
Duchesne	Questar Pipeline Company: Blind Canyon Compressor station	13079	-1263.217	161.644	0.11	6.07	0.26	0.26	0.16	2.99	30.08
	Davis County Total				0.57	206.67	4.32	2.54			
Emery	Alltel - McCook Ridge Cell Site	14003	-1127.118	-29.297	0.01	5.87	0.01	0.00	0.16	2.99	30.08
Emery	Book Cliffs Energy Corporation: Crude Oil/Used Oil Refinery	10265	-1156.195	-34.864	32.74	23.40	1.68	0.00	0.16	2.99	30.08
Emery	Consolidation Coal Company: Emery Coal Mine	10229	-1216.006	-46.757	0.03	0.40	5.11	0.30	0.16	2.99	30.08
Emery	Energy West Mining Company: Cottonwood Coal Prep Plant	10232	-1198.576	1.108	0.65	6.20	26.78	11.40	0.16	2.99	30.08
Emery	Energy West Mining Company: Deer Creek Mine	10239	-1201.947	22.524	0.00	0.00	0.00	1.10	0.16	2.99	30.08
Emery	Genwal Resources Incorporated: Crandall Canyon Mine	10225	-1206.879	36.083	0.20	3.02	1.71	0.58	0.16	2.99	30.08
Emery	PacifiCorp: Hunter Power Plant	10237	-1198.682	0.352	623.22	266.53	354.14	143.68	0.16	2.99	30.08
	Emery County Total				656.85	305.42	389.43	157.06			
Garfield	Western Rock Products Corporation: Panguitch Pit	12289	-1357.997	-123.412	1.10	7.40	1.96	1.15	0.16	2.99	30.08
	Garfield County Total				1.10	7.40	1.96	1.15			
Grand	ETC Canyon Pipeline	13014	-1145.042	32.802	0.00	4.10	0.00	0.00	0.16	2.99	30.08
Grand	ETC Canyon Pipeline	10268	-1032.876	2.661	0.03	0.00	2.52	3.22	0.16	2.99	30.08
Grand	EnCana Oil & Gas (USA) Incorporated: Lisbon Natural Gas Processing Plant	10034	-1064.392	-131.57	0.00	0.00	0.00	3.30	0.16	2.99	30.08
Grand	Fidelity Exploration & Production Company - Kane Springs Well #10-1	10267	-1111.939	-71.901	0.00	0.00	0.00	0.04	0.16	2.99	30.08
Grand	Fidelity Exploration & Production Company - Kane Springs Well #19-1A	10261	-1099.54	-86.348	0.00	0.02	0.01	0.05	0.16	2.99	30.08
Grand	Fidelity Exploration & Production Company - Kane Springs Well #25-19-34-1	10266	-1111.939	-71.901	0.00	0.13	0.01	0.06	0.16	2.99	30.08
Grand	Fidelity Exploration & Production Company - Kane Springs Well #27-1	10262	-1103.064	-77.281	0.00	0.05	0.01	0.06	0.16	2.99	30.08
Grand	LeGrand Johnson Construction Company: Moab site:asphalt plant/concrete batch	10639	-1074.833	-93.3	1.15	2.03	1.35	0.00	0.16	2.99	30.08
Grand	Mid-America Pipeline Company: Harley Dome Station	10263	-1036.371	-22.664	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Grand	Northwest Pipeline GP: Cisco Compressor Station	10259	-1059.11	-46.229	0.00	45.11	0.65	0.63	0.16	2.99	30.08
Grand	Northwest Pipeline GP: Moab Compressor Station	10627	-1081.532	-82.946	0.04	192.42	0.00	0.00	0.16	2.99	30.08
Grand	Running Foxes Petroleum Corporation-Cisco Gas Plant	14064	-1055.744	-42.068	0.00	19.09	0.00	0.00	0.16	2.99	30.08
	Grand County Total				1.21	262.95	4.54	7.36			
Juab	Nephi Sandstone: South Town Quarry & Concrete Batch Plant	12661	-1258.117	63.82	0.68	9.55	6.08	2.10	0.16	2.99	30.08
Juab	PacifiCorp: Currant Creek Power Plant	12524	-1262.005	86.975	7.40	141.60	60.50	60.50	0.16	2.99	30.08
Juab	Westroc Incorporated: Mona Aggregate Process & Concrete Batch Plant	12121	-1252.586	85.84	0.87	8.67	7.80	2.46	0.16	2.99	30.08
	Juab County Total				8.95	159.82	74.38	65.06			
Millard	Ash Grove Cement Company: Leamington Cement Plant	10303	-1289.292	59.632	0.00	0.00	0.00	94.45	0.16	2.99	30.08
Millard	Brush Resources Incorporated: Delta Mill	10311	-1311.68	53.176	0.22	9.84	24.77	60.14	0.16	2.99	30.08
Millard	Graymont Western US Incorporated: Cricket Mountain Plant	10313	-1352.952	0.117	16.08	1003.57	236.71	140.84	0.16	2.99	30.08
Millard	Intermountain Power Service Corporation: Intermountain Generation Station	10327	-1322.531	59.342	564.55	0.00	0.00	48.63	0.16	2.99	30.08
Millard	Kern River Gas Transmission Company: Fillmore Compressor Station	10320	-1328.597	-13.548	0.00	9.63	2.51	2.51	0.16	2.99	30.08
	Millard County Total				580.85	1023.04	263.99	346.57			
Morgan	Holcim (US) Inc.: Devil's Slide Plant	10007	-1206.92	213.877	181.18	250.74	0.00	0.00	0.16	2.99	30.08
Morgan	Wilkinson Construction: Drum Mix Asphalt Plant & Crushing Operation	10981	-1224.986	223.055	0.81	8.57	9.08	3.30	0.16	2.99	30.08
	Morgan County Total				181.99	259.31	9.08	3.30			
Portable Src	Tru Crushing Incorporated: Portable Equipment	12142	-1259.085	166.493	0.00	19.22	6.34	2.62	0.16	2.99	30.08
	Portable Total				0.00	19.22	6.34	2.62			
Salt Lake	Alliant Techsystems Incorporated: Bacchus Works: Plant 1/NIROP/Graphite Structures	10402	-1259.666	178.432	2.27	51.44	6.67	6.37	0.16	2.99	30.08
Salt Lake	Allroc Products: West Jordan Pit	12187	-1243.072	192.72	0.29	0.41	0.59	0.00	0.16	2.99	30.08

Table B4.1.1: Utah Included Permitted Industrial Sources (continued)

County	Facility	Site ID	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)
Salt Lake	Ames Construction Company: Portable Equipment - Temporary Locations	11941	-1250.631	180.362	5.97	43.06	30.68	6.56	0.16	2.99	30.08
Salt Lake	Ash Grove Cement Company: Murray Terminal	10389	-1244.184	174.756	0.00	0.00	0.06	0.00	0.16	2.99	30.08
Salt Lake	Asphalt Materials Incorporated: Bluffdale Sand Quarry	11981	-1249.986	152.475	0.24	2.40	5.24	1.22	0.16	2.99	30.08
Salt Lake	Asphalt Materials Incorporated: West Jordan Plant	10343	-1247.045	169.801	0.80	7.22	6.18	3.49	0.16	2.99	30.08
Salt Lake	Atlantic Southeast Airlines Incorporated: Aircraft Maintenance Facility	13094	-1247.045	169.801	0.00	0.04	0.00	0.00	0.16	2.99	30.08
Salt Lake	BD Medical: Becton Dickinson and Company	10377	-1245.534	165.067	0.31	3.73	0.23	0.00	0.16	2.99	30.08
Salt Lake	Binggeli Rock Products: Wasatch Boulevard Plant	10376	-1236.075	169.237	0.57	5.93	7.78	0.86	0.16	2.99	30.08
Salt Lake	Blanchard Metals Processing Company	10591	-1248.745	179.918	0.00	0.74	0.05	0.05	0.16	2.99	30.08
Salt Lake	Bland Recycling LLC: Sand & Gravel + Concrete Recycling	12298	-1257.719	173.6	0.30	3.79	1.95	0.78	0.16	2.99	30.08
Salt Lake	Boise Cascade Corporation: Boise Packaging & Newsprint L.L.C.	11178	-1253.588	188.829	0.01	2.44	3.74	3.74	0.16	2.99	30.08
Salt Lake	Boyer Company (The): Gateway Shopping Plaza Blocks A&B	12555	-1242.973	187.407	0.06	1.56	0.22	0.22	0.16	2.99	30.08
Salt Lake	Cabinetry by Karman: Cabinet Manufacturing	10558	-1245.123	172.41	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Salt Lake	Central Valley Water Reclamation Fac.: Wastewater Treatment Plant	10414	-1245.076	180.686	2.42	14.12	1.13	0.72	0.16	2.99	30.08
Salt Lake	Cephalon Incorporated: Pharmaceuticals Manufacturing	13128	-1245.076	180.686	0.06	0.28	0.07	0.00	0.16	2.99	30.08
Salt Lake	Chevron Products Co - SL Refinery: Salt Lake Refinery	10119	-1243.446	193.59	2200.66	783.75	72.31	53.21	0.16	2.99	30.08
Salt Lake	Cliff Johnson Excavating: Asphalt & Concrete Recycling	13309	-1349.806	210.866	0.00	0.03	6.42	0.90	0.16	2.99	30.08
Salt Lake	Construction Recycling Incorporated: Construction Debris Recycling	12288	-1246.735	187.254	1.12	5.88	0.00	0.00	0.16	2.99	30.08
Salt Lake	Cottonwood Hospital Medical Center: Cottonwood Hospital	10405	-1243.3	163.701	0.02	3.07	0.23	0.23	0.16	2.99	30.08
Salt Lake	Dannon Company Incorporated (The): West Jordan Yogurt Production	11652	-1257.222	168.191	0.00	3.17	0.26	0.26	0.16	2.99	30.08
Salt Lake	Delta Air Lines Incorporated: Delta Airlines at SLC Int'l Airport	11664	-1246.707	196.873	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Salt Lake	Easton Technical Products: Tubing Manufacturing Facility	10365	-1251.608	190.088	0.35	5.84	0.98	0.49	0.16	2.99	30.08
Salt Lake	Fashion Cabinet Manufacturing Inc.: Cabinet Manufacturing Facility	10482	-1255.851	167.901	0.00	0.06	0.01	0.00	0.16	2.99	30.08
Salt Lake	Geneva Rock Products: Bacchus Pit	11768	-1256.648	174.887	3.12	13.94	20.49	2.22	0.16	2.99	30.08
Salt Lake	Geneva Rock Products: Mount Jordan Operations	12776	-1256.648	174.887	7.74	40.21	153.27	15.81	0.16	2.99	30.08
Salt Lake	Geneva Rock Products: Pelican Point Limestone	10843	-1249.499	130.888	2.33	6.08	36.98	0.00	0.16	2.99	30.08
Salt Lake	Geneva Rock Products: Point of the Mountain Facility	10565	-1248.844	154.025	19.43	105.95	94.08	12.12	0.16	2.99	30.08
Salt Lake	Granite Construction Company: Cottonwood Facility	10407	-1236.463	169.893	5.90	57.11	5.48	0.00	0.16	2.99	30.08
Salt Lake	Harper Contracting: 2300 North Concrete Plant	13133	-1379.832	-55.995	0.03	4.12	4.28	0.52	0.16	2.99	30.08
Salt Lake	Harper Contracting: Aggregate Processing & Concrete Plant - Daybreak	13102	-1201.478	174.404	0.05	0.47	0.10	0.08	0.16	2.99	30.08
Salt Lake	Harper Contracting: Main Office/Pit #6	11797	-1261.11	176.754	0.60	9.15	1.12	3.14	0.16	2.99	30.08
Salt Lake	Harper Contracting: Parleys Canyon Aggregate Facility	12058	-1233.416	180.258	0.00	0.00	0.00	2.43	0.16	2.99	30.08
Salt Lake	Harper Contracting: Pit #10	10569	-1256.454	175.197	0.00	1.43	0.00	9.25	0.16	2.99	30.08
Salt Lake	Harper Contracting: Pit #5 - Salt Lake County	11557	-1258.92	171.902	0.22	3.16	0.06	3.20	0.16	2.99	30.08
Salt Lake	Hexcel Corporation: Salt Lake Operations	11386	-1259.682	178.509	1.86	31.00	0.00	5.73	0.16	2.99	30.08
Salt Lake	Huish Detergents Incorporated: Detergent Manufacturing	10463	-1249.582	183.833	0.05	8.22	25.26	0.00	0.16	2.99	30.08
Salt Lake	IASIS Healthcare: Salt Lake Regional Medical Center	10440	-1238.619	186.346	0.10	0.75	0.00	0.00	0.16	2.99	30.08
Salt Lake	Interstate Brick Company: Brick Manufacturing Plant	10423	-1256.361	167.086	27.35	49.18	42.38	8.29	0.16	2.99	30.08
Salt Lake	Kennecott Barneys Canyon Mining Company: Barney's Canyon Mine	10501	-1264.466	171.166	0.35	4.64	0.33	0.33	0.16	2.99	30.08
Salt Lake	Kennecott Utah Copper Corporation: Mine & Copperton Concentrator	10571	-1267.346	164.25	0.00	1420.81	1333.01	290.73	0.16	2.99	30.08
Salt Lake	Kennecott Utah Copper Corporation: Power Plant/ Lab/ Tailings Impoundment	10572	-1262.486	182.654	564.81	441.61	20.98	9.41	0.16	2.99	30.08
Salt Lake	Kennecott Utah Copper Corporation: Smelter & Refinery	10346	-1268.066	185.535	175.05	0.00	26.65	19.69	0.16	2.99	30.08
Salt Lake	Kern River Gas Transmission Company: Salt Lake City Compressor Station	12596	-1246.274	185.265	0.12	39.73	3.21	3.21	0.16	2.99	30.08
Salt Lake	LDS Church: LDS Central Heating Plant	10578	-1242.767	186.938	0.00	2.90	0.10	0.70	0.16	2.99	30.08
Salt Lake	Lakeview Rock Products: Gravel Pit	10439	-1242.872	192.997	0.26	5.80	4.96	4.45	0.16	2.99	30.08
Salt Lake	Linde Hydrogen Plant: Hydrogen Gas Production	13091	-1243.248	105.938	0.40	16.80	3.81	3.81	0.16	2.99	30.08
Salt Lake	Moog Aircraft Group: Montek Company - Salt Lake Operations	10557	-1249.287	182.911	0.05	0.85	0.10	0.10	0.16	2.99	30.08
Salt Lake	Murray City Power Department: Electrical Generation Plant	10348	-1243.692	174.238	0.03	3.85	0.57	0.57	0.16	2.99	30.08
Salt Lake	Newspaper Agency Corp (MediaOne): 4770 South 5600 West	13150	-1254.846	177.607	0.01	0.84	0.06	0.06	0.16	2.99	30.08
Salt Lake	Olympia Sales Company: Cabinet Manufacturing Facility	10562	-1244.174	183.713	0.00	0.00	4.38	0.00	0.16	2.99	30.08
Salt Lake	Owens Corning: Western Fiberglass - Salt Lake City Plant	10033	-1250.763	186.521	3.76	5.52	63.00	57.96	0.16	2.99	30.08
Salt Lake	Primary Children's Medical Center: Primary Children's Medical Center	10461	-1246.255	187.951	0.15	17.61	7.07	0.00	0.16	2.99	30.08
Salt Lake	Quality Plating Company: Custom Plating Facility	10594	-1243.347	186.286	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Salt Lake	Qwest: Standby Diesel Emergency Generator	10521	-1241.263	186.191	0.41	2.44	0.02	0.02	0.16	2.99	30.08
Salt Lake	Qwest: Standby Diesel Emergency Generators	11432	-1241.475	186.195	0.20	1.67	0.07	0.07	0.16	2.99	30.08
Salt Lake	Recot	11297	-1256.019	177.803	0.05	7.13	5.13	3.90	0.16	2.99	30.08
Salt Lake	Reynolds Sand & Gravel: Aggregate Production - WVC Pit #2	12981	-1257.508	176.54	0.90	9.12	6.19	2.09	0.16	2.99	30.08
Salt Lake	Reynolds Sand & Gravel: Sand & Gravel Operations Pit #1	12108	-1261.453	182.887	1.26	11.50	10.76	2.92	0.16	2.99	30.08
Salt Lake	Rocky Mountain Machine Shop Inc.: Salt Lake City machine shop	12104	-1247.904	185.138	0.00	0.11	0.00	0.00	0.16	2.99	30.08
Salt Lake	Salt Lake City Corp.: 451 S State St.	12815	-1055.744	-42.068	0.01	0.09	0.01	0.00	0.16	2.99	30.08
Salt Lake	Salt Lake City Department of Airports: Salt Lake City International Airport	10450	-1248.302	189.974	1.47	11.82	1.57	0.86	0.16	2.99	30.08
Salt Lake	Salt Lake Community College: Redwood Campus	10505	-1247.813	176.998	0.03	2.01	0.31	0.00	0.16	2.99	30.08
Salt Lake	Salt Lake Community College: South City Campus	11751	-1242.07	184.735	0.01	0.44	0.07	0.00	0.16	2.99	30.08
Salt Lake	Salt Lake County: Salt Palace	11295	-1241.91	185.706	0.16	7.99	1.92	1.92	0.16	2.99	30.08
Salt Lake	Salt Lake Energy Systems LLC: Power Plant at Salt Lake Valley Landfill	13104	-1241.91	185.706	12.40	27.80	4.80	4.80	0.16	2.99	30.08
Salt Lake	Salt Lake Valley Sand and Gravel: Salt Lake Valley Sand and Gravel	10379	-1249.822	152.603	1.70	18.00	20.40	20.40	0.16	2.99	30.08
Salt Lake	Salt Lake Valley Solid Waste Management: Salt Lake Valley Landfill & Transfer Station	11362	-1254.088	185.829	5.67	53.70	107.89	22.81	0.16	2.99	30.08
Salt Lake	Skywest Airlines: Skywest Airlines at SLC Int'l Airport	11674	-1247.413	189.078	8.44	81.23	8.51	8.51	0.16	2.99	30.08
Salt Lake	Sorensen Sand and Gravel: West Jordan Sand & Gravel Processing	11983	-1260.073	168.263	1.41	18.10	16.00	4.48	0.16	2.99	30.08
Salt Lake	Staker & Parson Companies: Point East	11234	-1246.758	157.233	12.09	23.09	24.12	6.04	0.16	2.99	30.08
Salt Lake	Tesoro West Coast: Salt Lake City Refinery	10335	-1242.528	189.597	908.57	366.33	139.87	74.80	0.16	2.99	30.08
Salt Lake	Textile Care Services: Laundry Facility	12255	-1248.195	183.478	0.01	2.01	0.15	0.15	0.16	2.99	30.08
Salt Lake	Trans-Jordan Cities: Trans-Jordan Landfill	11977	-1259.085	166.493	3.31	28.53	21.22	12.62	0.16	2.99	30.08
Salt Lake	University of Utah: University of Utah facilities	10354	-1237.674	184.353	0.77	63.67	4.56	4.53	0.16	2.99	30.08
Salt Lake	Utah Department of Natural Resources: Division of Wildlife Resources Area Landfill	11976	-1254.326	185.905	0.00	0.00	0.37	0.06	0.16	2.99	30.08
Salt Lake	Varian Associates Incorporated: Manufacturing Facility	10358	-1248.244	184.077	0.01	0.21	0.02	0.01	0.16	2.99	30.08
Salt Lake	Watson Laboratories Incorporated: Pharmaceutical Manufacturing Facility	10517	-1236.546	184.042	0.15	4.83	0.42	0.42	0.16	2.99	30.08
Salt Lake	Wind River Investments LC: Murray Asphalt Crushing Plant	12093	-1243.403	177.388	1.34	20.94	4.22	1.46	0.16	2.99	30.08
Salt Lake	CER Generation II	12495	-1255.415	177.564	0.50	35.32	11.69	11.69	0.16	2.99	30.08
	Salt Lake County Total				3990.09	4028.76	2386.82	717.46			
San Juan	Denison Mines (USA) Corp.: White Mesa Mill	11205	-1090.474	-193.629	0.00	0.00	0.00	0.00	0.16	2.99	30.08
San Juan	Holliday Construction Incorporated: Blanding Pit	12868	-1206.92	213.877	4.51	29.13	4.98	0.00	0.16	2.99	30.08
San Juan	Holliday Construction Incorporated: Bluff Pit	12173	-1114.206	-177.103	0.00	0.00	2.29	0.00	0.16	2.99	30.08
San Juan	Lisbon Valley Mining Company LLC: Lisbon Valley Open Pit Copper Mine	11462	-1050.761	-135.532	1.58	46.75	54.04	54.04	0.16	2.99	30.08
	San Juan County Total				6.09	75.88	61.31	54.04			
Sanpete	Central Utah Correctional Facility: Gunnison Correctional Facility	10648	-1265.176	10.062	0.22	13.10	8.30	0.11	0.16	2.99	30.08
Sanpete	George W. Johansen Construction Co.: Johansen Sand and Gravel	11703	-1223.6	44.732	0.62	5.63	5.26	2.36	0.16	2.99	30.08
Sanpete	RC Rental & Sales: Portable Aggregate Plant	13375	-1246.807	19.321	0.97	4.86	2.25	0.62	0.16	2.99	30.08
Sanpete	Snow College: Snow College	10652	-1241.719	29.012	0.02	2.24	0.17	0.17	0.16	2.99	30.08
Sanpete	Western Rock Products Corporation: Centerfield Asphalt Plant	10645	-1265.346	5.794	1.27	9.37	2.44	1.25	0.16	2.99	30.08
	Sanpete County Total				3.10	35.20	18.42	4.51			
Sevier	Canyon Fuel Company LLC: SUFCO (Salina Canyon Coal Mine)	10665	-1235.055	-21.771	6.61	74.90	15.85	2.16	0.16	2.99	30.08
Sevier	G-P Gypsum: Sigurd Plant	10653	-1282.773	-23.202	0.00	2.83	8.84	0.00	0.16	2.99	30.08
Sevier	Hales Sand and Gravel Incorporated: Elsinore Pit	10655	-1301.412	-36.816	0.23	9.51	0.00	1.38	0.16	2.99	30.08
Sevier	Hawley Rock/Industrial Rock Products: Crushing and Screening Operation	12066	-1302.063	-38.349	0.98	13.49	4.99	0.00	0.16	2.99	30.08
Sevier	Redmond Minerals Incorporated: Bentonite Production	10035	-1270.883	-0.826	0.49	2.03	3.11	0.79	0.16	2.99	30.08
Sevier	Redmond Minerals Incorporated: Salt Production - Bagging Plant	10675	-1270.883	-0.826	0.60	4.69	8.43	2.42	0.16	2.99	30.08
Sevier	United States Gypsum Company: Sigurd Plant	10654	-1281.813	-20.777	0.47	10.83	66.65	21.26	0.16	2.99	30.08
Sevier	Western Clay Company: Aurora Bentonite/Gypsum Milling Plant	10663	-1311.672	-37.349	1.95	10.65	15.66	7.95	0.16	2.99	30.08
	Sevier County Total				11.33	128.93	123.53	35.96			
Summit	Crandall Crushing: Aggregate Crusher & Asphalt Plant	10685	-1195.523	175.248	0.00	0.00	0.00	0.00	0.16	2.99	30.08

Table B4.1.1: Utah Included Permitted Industrial Sources (continued)

County	Facility	Site ID	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)
Summit	DC Transport & Excavating Inc: Aggregate Pit	13002	-1250.121	145.646	4.83	24.60	8.10	0.00	0.16	2.99	30.08
Summit	DC Transport & Excavating Inc: Kamas Pit	13347	-1250.121	145.646	1.18	13.77	3.58	1.86	0.16	2.99	30.08
Summit	Geary Construction Incorporated: Wanship Pit	10695	-1200.737	188.475	2.82	10.92	1.26	0.00	0.16	2.99	30.08
Summit	Harper Contracting: Aggregate Pit #24 - Brown Canyon	12432	-1201.478	174.404	0.00	0.00	0.00	0.22	0.16	2.99	30.08
Summit	MBG Development LLC: Portable Crushing & Screening Equipment	13249	-1209.203	181.368	0.21	1.18	4.78	1.26	0.16	2.99	30.08
Summit	Rees's Enterprise: Coalville Pit	11878	-1198.986	197.016	0.02	0.15	0.33	0.13	0.16	2.99	30.08
Summit	Rees's Enterprise: Portable Equipment based at Coalville Pit	11043	-1256.761	-84.464	2.69	20.31	5.34	1.88	0.16	2.99	30.08
Summit	Utelite Corporation: Shale Processing	10676	-1201.813	178.799	145.13	205.09	36.57	10.49	0.16	2.99	30.08
Summit	Whiting Oil and Gas Corporation: Bridger Lake Plant	10679	-1107.856	187.816	0.06	116.91	1.79	1.79	0.16	2.99	30.08
Summit	Yellow Creek Plant	10680	-1178.019	196.183	0.01	1.20	0.09	0.09	0.16	2.99	30.08
	Summit County Total				156.95	394.13	61.84	17.72			
Tooele	Bolinder Companies Incorporated: Crushing & Aggregate Operations	13257	-1253.588	188.829	0.26	3.72	0.36	0.01	0.16	2.99	30.08
Tooele	Cargill Incorporated--Salt Division: Timpie Salt Processing Plant	10722	-1305.677	195.585	3.85	48.81	53.08	53.08	0.16	2.99	30.08
Tooele	Chemical Lime Company: Grantsville Plant	10707	-1297.978	186.936	5.91	75.47	99.10	58.96	0.16	2.99	30.08
Tooele	Clean Harbors Aragonite LLC: Hazardous Waste Storage/Incineration	10725	-1331.518	198.505	1.60	4.57	0.00	1.85	0.16	2.99	30.08
Tooele	Clean Harbors Grassy Mountain LLC: Grassy Mountain Landfill Facility	10720	-1349.806	210.866	0.00	0.00	14.24	0.00	0.16	2.99	30.08
Tooele	Deseret Chemical Depot: Deseret Chemical Depot (South Area)	11339	-1284.485	145.235	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Tooele	Dugway Proving Ground: U.S. Army-Dugway Proving Ground	10706	-1365.734	136.432	10.94	73.36	0.00	0.00	0.16	2.99	30.08
Tooele	Geneva Rock Products: Bauer Plant - Aggregate Pit and Concrete Batch	13039	-1256.648	174.887	2.87	27.40	22.56	2.78	0.16	2.99	30.08
Tooele	Jack B. Parsons Company: Bauer Pit & Batch Plant	11572	-1286.032	160.279	0.30	4.57	0.45	0.00	0.16	2.99	30.08
Tooele	Morton International/Morton Salt Div.: Morton Salt	10726	-1296.137	187.077	3.20	28.72	0.00	0.00	0.16	2.99	30.08
Tooele	Solar Aluminum Technology Services: Aluminum Recovery Facility	10729	-1387.147	209.068	2.63	29.22	12.28	0.00	0.16	2.99	30.08
Tooele	Staker & Parson Companies: Erda Pit & Hot Plant	10712	-1276.916	177.52	1.03	14.55	11.97	3.55	0.16	2.99	30.08
Tooele	Tooele Army Depot: Tooele Army Depot	11594	-1284.45	168.3	4.26	27.78	2.72	0.97	0.16	2.99	30.08
Tooele	US Magnesium LLC: Rowley Plant	10716	-1308.639	214.481	32.56	1019.37	546.43	366.34	0.16	2.99	30.08
Tooele	Utah Refractories Corporation: Silica Stone Quarry	10728	-1297.039	162.882	0.02	0.24	3.10	0.10	0.16	2.99	30.08
	Tooele County Total				69.43	1357.78	766.29	487.64			
Uintah	Northwest Pipeline GP: Vernal Compressor Station (Grand Father Equipment)	10756	-1032.869	133.067	0.70	39.82	0.98	0.39	0.16	2.99	30.08
Uintah	Simplot Phosphates LLC: Vernal Phosphate Operations	10749	-1045.093	138.039	7.51	73.13	76.50	20.28	0.16	2.99	30.08
	Uintah County Total				8.21	112.95	77.48	20.67			
Utah	Alcoa Extrusions Incorporated: Unrecycled Aluminum Scrap Production	10847	-1232.952	112.562	0.10	14.66	6.62	2.63	0.16	2.99	30.08
Utah	Brigham Young University: Main Campus	10790	-1231.009	126.559	97.70	87.87	3.62	2.46	0.16	2.99	30.08
Utah	C & C Cast Polymers Incorporated: Cultured Marble Manufacturing	12736	-1117.844	115.56	0.00	0.07	0.21	0.21	0.16	2.99	30.08
Utah	Construction Products Company: Pelican Point Facility	11964	-1250.134	130.765	1.38	2.29	0.94	0.00	0.16	2.99	30.08
Utah	Crystal Animal Products Incorporated: Lehi Manufacturing Facility	11190	-1250.121	145.646	0.02	1.40	0.08	0.03	0.16	2.99	30.08
Utah	Dunn Construction: Portable Equipment - Temporary Locations	11833	-1242.355	166.36	1.58	19.27	1.62	0.78	0.16	2.99	30.08
Utah	Enterprize Paving: Asphalt Plant #ADM 277-93	11090	-1238.749	137.484	2.24	1.47	0.36	0.06	0.16	2.99	30.08
Utah	Geneva Nitrogen Plant	10825	-1237.069	135.711	0.01	12.15	0.00	0.00	0.16	2.99	30.08
Utah	Geneva Rock Products: Orem Hot Mix Asphalt Plant & Concrete Batch Plants	10820	-1237.024	134.244	18.26	14.79	9.64	3.62	0.16	2.99	30.08
Utah	Global Coatings Incorporated: Steel Coating Application Facility	10880	-1236.81	140.777	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Utah	Goodfellow Corporation	14068	-1232.792	136.76	0.03	0.41	0.24	0.08	0.16	2.99	30.08
Utah	H E Davis Construction: Salem Pit	11805	-1232.734	103.259	1.25	0.00	7.84	0.00	0.16	2.99	30.08
Utah	Kenny Seng Construction Incorporated: Aggregate Production Equipment	11822	-1233.516	128.972	0.00	25.37	6.54	3.23	0.16	2.99	30.08
Utah	Kern River Gas Transmission Company: Elberta Compressor Station	12514	-1264.41	122.026	0.10	36.06	2.89	2.89	0.16	2.99	30.08
Utah	Orica USA Inc.: Lehi Plant	10861	-1252.691	143.736	0.62	0.34	2.61	0.68	0.16	2.99	30.08
Utah	PacifiCorp: Lakeside Power Plant	13031	-1238.415	137.084	2.60	95.70	13.30	11.10	0.16	2.99	30.08
Utah	Pacific States Cast Iron Pipe Company: Pipe Casting Plant	10794	-1230.559	121.044	2.12	65.03	7.99	4.99	0.16	2.99	30.08
Utah	Payson City Corporation: Payson City Power	10823	-1242.194	105.798	0.00	0.00	0.02	0.02	0.16	2.99	30.08
Utah	Provo City Power: Power Plant	10795	-1232.562	126.512	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Utah	Questar Pipeline Company: Thistle Creek Compression Station	13083	-1176.215	52.502	0.01	0.28	0.02	0.02	0.16	2.99	30.08
Utah	RT Manufacturing Incorporated: RT Manufacturing - Orem Facility	11867	-1236.481	135.649	0.00	0.59	0.03	0.02	0.16	2.99	30.08
Utah	Rayloc - Division of Genuine Parts Co.: Auto Parts Remanufacturing	10808	-1240.84	106.979	0.00	0.61	19.24	18.76	0.16	2.99	30.08
Utah	ShawCor Pipe Protection LLC: Geneva Pipe Coating Facility	12073	-1239.28	137.136	5.00	5.00	13.00	0.00	0.16	2.99	30.08
Utah	South Utah Valley Solid Waste District: Bayview Landfill	11975	-1264.47	122.024	2.15	24.13	23.70	17.27	0.16	2.99	30.08
Utah	Springville City Corporation: Whitehead Power Plant	10819	-1229.929	118.585	0.06	14.64	0.49	0.49	0.16	2.99	30.08
Utah	Staker & Parson Companies: Gomex Pit: Aggregate Processing Plant	12130	-1228.485	106.942	0.10	1.07	5.08	1.24	0.16	2.99	30.08
Utah	Staker & Parson Companies: Keigley Quarry	12444	-1246.942	99.239	7.34	9.30	15.27	3.57	0.16	2.99	30.08
Utah	Staker & Parson Companies: Lehi-Peck Pit	12085	-1254.371	146.219	0.39	4.32	11.65	2.62	0.16	2.99	30.08
Utah	Staker & Parson Companies: Point West Operations	10841	-1249.824	151.731	0.75	8.25	34.42	11.71	0.16	2.99	30.08
Utah	Staker & Parson Companies: Spanish Fork	10821	-1235.988	110.883	0.22	2.33	7.86	3.29	0.16	2.99	30.08
Utah	Sunroc Corporation: Santaquin Aggregate Facility	10814	-1232.734	103.259	3.94	21.02	48.85	6.22	0.16	2.99	30.08
Utah	T.L.C. Rock Products: Lehi Pit	12012	-1232.734	103.259	1.58	24.10	6.71	6.71	0.16	2.99	30.08
Utah	T.L.C. Rock Products: Saratoga Springs	13139	-1232.734	103.259	0.32	3.31	4.73	0.00	0.16	2.99	30.08
Utah	TM Crushing: Portable Aggregate Equipment	13244	-1251.666	141.044	6.97	44.58	28.90	1.70	0.16	2.99	30.08
Utah	Utah Assoc. Municipal Power Systems: Nebo (Payson) Power Plant	12825	-1237.674	184.353	0.90	27.40	9.50	9.50	0.16	2.99	30.08
Utah	Utah Valley Regional Medical Center: Provo Hospital	11846	-1232.529	127.006	0.20	3.55	0.36	0.36	0.16	2.99	30.08
Utah	Utah Valley State College: Campus Engineering	10849	-1236.114	130.73	0.01	0.13	0.01	0.01	0.16	2.99	30.08
Utah	Vanrok LLC: Aggregate Plant - Provo	13303	-1230.248	122.185	1.13	8.79	3.99	1.15	0.16	2.99	30.08
Utah	Vanrok LLC: Aggregate Plant - Provo Canyon	13304	-1230.248	122.185	0.90	7.36	4.06	1.14	0.16	2.99	30.08
Utah	Western Pipe Coaters and Engineers: Western Pipe Coaters and Engineers	10835	-1238.319	136.853	0.17	1.40	0.38	0.03	0.16	2.99	30.08
Utah	Westroc Incorporated: Highland Aggregate Pit	11436	-1237.511	149.235	1.21	11.89	18.82	5.34	0.16	2.99	30.08
	Utah County Total				161.37	600.92	321.59	123.91			
Wasatch	Binggeli Rock Products: Gravel Pit - Concrete Plant	10885	-1211.586	147.272	0.87	9.03	5.63	1.95	0.16	2.99	30.08
Wasatch	Granite Construction Company: Deer Creek Asphalt Plant	12676	-1236.463	169.893	0.09	0.70	0.74	0.00	0.16	2.99	30.08
Wasatch	Heber Light and Power Company: Power Plant	10884	-1207.142	153.001	0.05	154.46	0.36	0.36	0.16	2.99	30.08
Wasatch	Staker & Parson Companies: Wallsburg Pit	12392	-1210.291	139.099	0.01	0.12	0.08	0.00	0.16	2.99	30.08
Wasatch	West Valley Sand & Gravel Incorporated: Aggregate Processing	13073	-1245.611	226.629	1.54	13.50	5.46	0.00	0.16	2.99	30.08
	Wasatch County Total				2.56	177.81	12.27	2.31			
Washington	Bryce Christensen Excavating Inc.: BCE St. George Aggregate Production Plant	12900	-1311.68	53.176	0.00	0.00	5.47	0.00	0.16	2.99	30.08
Washington	Gilbert Development Corporation: Aggregate Crushing - SR 9 Pit	12899	-1223.6	44.732	2.08	24.46	3.46	0.00	0.16	2.99	30.08
Washington	Progressive Contracting Incorporated: Aggregate Mining	12898	-1246.255	187.951	1.51	7.65	3.32	0.00	0.16	2.99	30.08
Washington	Quality Excavation Inc.: Aggregate Plant - Fort Pierce Industrial Park	12934	-1378.632	-74.739	0.00	0.00	11.77	0.50	0.16	2.99	30.08
Washington	Sunroc Corporation: Anderson Junction Pit	12680	-1350.953	-70.953	0.00	0.00	0.47	0.47	0.16	2.99	30.08
	Washington County Total				3.59	32.11	24.49	0.97			
Wayne	Brown Brothers Construction: Gravel Crushing & Washing	12871	-1231.009	126.559	1.24	15.97	1.52	0.00	0.16	2.99	30.08
Wayne	Denison Mines (USA) Corp. - Tony M Mine	14010	-1196.955	-117.117	0.03	62.90	3.90	3.20	0.16	2.99	30.08
	Wayne County Total				1.27	78.87	5.42	3.20			
Weber	Autoliv North America: Ogden Generant Facility	10025	-1242.836	236.074	0.00	0.00	0.00	0.00	0.16	2.99	30.08
Weber	Autoliv North America: Ogden Module Facility	11602	-1243.478	236.271	0.07	1.35	0.09	0.00	0.16	2.99	30.08
Weber	Granite Construction Company: West Haven Asphalt Plant	12272	-1256.6	232.978	6.97	10.99	0.00	0.00	0.16	2.99	30.08
Weber	Levolor Home Fashions: Manufacturing Facility	10927	-1243.725	237.375	0.00	0.00	0.00	0.15	0.16	2.99	30.08
Weber	Rail Bearing Service: Rail Road Wheel Bearing Refurbishing Plant	11246	-1245.371	235.968	0.00	0.12	1.20	0.02	0.16	2.99	30.08
Weber	Sem Materials	12398	-1251.185	189.475	0.07	6.68	0.00	0.00	0.16	2.99	30.08
Weber	Staker & Parson Companies: South Weber Operations	10928	-1237.183	226.786	0.95	9.83	12.81	3.20	0.16	2.99	30.08
Weber	Weber County School District: South Ogden Junior High School	12000	-1245.611	226.629	0.00	0.33	0.03	0.03	0.16	2.99	30.08
	Weber County Total				8.06	29.30	14.12	3.39			

Table B4.1.2: Colorado Included Permitted Industrial Sources

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
COLORADO LIME COMPANY DBA CALCO	83CH052-5	-778.09	-123.051	3.57	1.31	0.01	3.05	0.46	15.82	321.89
ACA PRODUCTS	07CH0085	-787.931	-89.955	0.04	0.34	0.25	5.49	1.22	30.08	421.89
ACA PRODUCTS	07CH0085	-787.931	-89.955	0.00	0.00	0.53	5.49	1.22	30.08	421.89
COLORADO QUARRIES INC	06CH0459	-772.038	-126.89	0.00	15.00	1.20	0.00	0.51	30.08	294.11
RIVERSIDE CREMATORY	07CH0547	-778.3	-123.102	0.71	1.17	2.08	5.18	0.55	5.88	975.78
DELTA COUNTY-PIG MESA	06DL0994F	-949.641	-77.236	0.00	0.00	0.07	0.00	0.51	30.08	294.11
DELTA COUNTY-PIG MESA	06DL0994F	-949.641	-77.236	0.00	0.00	6.84	0.00	0.51	30.08	294.11
DELTA COUNTY ELLISON GRAVEL PIT	91DL833F	-950.005	-81.399	0.00	0.00	17.32	0.00	0.51	30.08	294.11
DELTA COUNTY TRIANTOS GRAVEL PIT	92DL019F	-959.889	-78.922	0.00	0.00	6.03	0.00	0.51	30.08	294.11
DELTA COUNTY LEMOINE GRAVEL PIT	92DL020F	-921.178	-75.9	0.00	0.00	4.68	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	94DL199F	-953.002	-78.593	0.00	0.00	9.38	0.00	0.51	30.08	294.11
BOWIE RESOURCES LLC - BOWIE NO 2 MINE	96DL103-6	-907.401	-65.144	0.00	0.00	43.01	0.00	0.51	30.08	294.11
BOWIE RESOURCES LLC - BOWIE NO 2 MINE	03DL0596	-907.401	-65.144	0.00	0.00	0.72	0.00	0.51	30.08	294.11
BOWIE RESOURCES LLC - BOWIE NO 2 MINE	03DL0923F	-907.401	-65.144	0.00	0.00	31.84	0.00	0.51	30.08	294.11
BOWIE RESOURCES LLC - BOWIE NO 2 MINE	04DL0560	-907.401	-65.144	0.00	0.00	0.02	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	99DL0172F	-953.677	-79.796	0.00	0.00	0.57	0.00	0.51	30.08	294.11
DELTA MUNICIPAL LIGHT & POWER (CITY OF		-955.032	-81.763	0.04	5.96	0.06	0.00	0.51	30.08	294.11
ELAM CONSTRUCTION (WAS BENNETTS	97DL0750F	-967.834	-76.073	0.00	0.00	1.31	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - DELTA-JACKSON PIT	99DL0584F	-953.287	-78.566	0.00	0.00	0.01	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - DELTA-JACKSON PIT	99DL0584F	-953.287	-78.566	0.00	0.00	0.34	0.00	0.51	30.08	294.11
HIGH MESA GRAVEL PIT	00DL0789F	-942.141	-76.14	0.00	0.00	13.51	0.00	0.51	30.08	294.11
ELAM CONSTRUCTION INC DUBS PIT	02DL0625F	-959.567	-79.145	0.00	0.00	5.30	0.00	0.51	30.08	294.11
GUNNISON ENERGY - SPAULDING PEAK CS	04DL0542	-940.149	-54.751	0.03	28.90	0.55	7.62	0.36	27.10	699.67
DIAMOND LAZY L. RANCH - JANET PIT	04DL0811F	-920.331	-75.815	0.00	0.00	0.01	0.00	0.51	30.08	294.11
DIAMOND LAZY L. RANCH - JANET PIT	04DL0811F	-920.331	-75.815	0.00	0.00	1.22	0.00	0.51	30.08	294.11
ALTERNATIVE MINING METHODS	04DL1196	-967.788	-76.096	0.00	0.00	0.17	0.00	0.51	30.08	294.11
ALTERNATIVE MINING METHODS	04DL1196	-967.788	-76.096	0.00	0.00	0.84	0.00	0.51	30.08	294.11
ALTERNATIVE MINING METHODS	04DL1196	-967.788	-76.096	0.00	0.00	0.01	0.00	0.51	30.08	294.11
BENSON BROTHERS - PIG MESA	05DL0300F	-948.835	-76.903	0.00	0.00	0.11	0.00	0.51	30.08	633.80
BENSON BROTHERS - PIG MESA	05DL0300F	-948.835	-76.903	0.00	0.00	5.99	0.00	0.51	30.08	633.80
OLDCASTLE SW GROUP - ANDERSON PIT	05DL0281F	-951.696	-78.755	0.00	0.00	0.03	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP - ANDERSON PIT	05DL0281F	-951.696	-78.755	0.00	0.00	9.93	0.00	0.51	30.08	294.11
UNITED COMPANIES - DELTA BATCHING PLANT	06DL0266	-950.951	-79.261	0.00	0.00	0.33	0.00	0.51	30.08	294.11
UNITED COMPANIES - DELTA BATCHING PLANT	06DL0266	-950.951	-79.261	0.00	0.00	4.58	0.00	0.51	30.08	294.11
BENSON BROTHERS - RED SHALE PIT	06DL0709F	-943.589	-61.256	0.00	0.00	0.05	0.00	0.51	30.08	294.11
BENSON BROTHERS - RED SHALE PIT	06DL0709F	-943.589	-61.256	0.00	0.00	1.17	0.00	0.51	30.08	294.11
MID-AMERICA PIPELINE CO DOVE CR STA	06DO1224	-1044.256	-169.988	0.01	28.22	0.46	8.53	0.61	52.58	767.44
QUESTAR E&P - ISLAND BUTTE A	93DO1648-1	-1050.371	-199.25	0.00	0.33	0.00	3.66	0.25	30.08	838.56
QUESTAR E&P - ISLAND BUTTE A	93DO1648-1	-1050.371	-199.25	0.00	40.00	0.00	3.66	0.25	30.08	838.56
QUESTAR E&P - ISLAND BUTTE A	93DO1648-1	-1050.371	-199.25	0.00	0.00	0.32	3.66	0.25	30.08	838.56
QUESTAR E&P - ISLAND BUTTE A	93DO1648-1	-1050.371	-199.25	0.00	0.00	0.00	3.66	0.25	30.08	838.56
TRANSCOLORADO GAS TRANSMISSION CO	98DO0184	-997.624	-196.4	0.00	17.26	0.00	15.24	0.58	37.34	633.80
TRANSCOLORADO GAS TRANSMISSION CO	98DO0184	-997.624	-196.4	0.00	0.00	0.73	15.24	0.58	37.34	633.80
TRANSCOLORADO GAS TRANSMISSION CO	98DO0184	-997.624	-196.4	0.04	0.00	0.00	15.24	0.58	37.34	633.80
TRANSCOLORADO GAS TRANSMISSION CO	98DO0185	-997.624	-196.4	0.01	5.55	0.07	15.24	0.58	37.34	633.80
TRANSCOLORADO GAS TRANSMISSION CO		-997.624	-196.4	0.03	12.47	0.58	7.62	0.41	88.48	731.89
TRANSCOLORADO GAS TRANSMISSION CO		-1049.315	-189.737	0.00	2.76	0.00	0.00	0.00	0.00	0.00
TRANSCOLORADO GAS TRANSMISSION CO		-1049.315	-189.737	0.00	0.00	0.08	0.00	0.00	0.00	0.00
TRANSCOLORADO GAS TRANSMISSION CO		-1049.315	-189.737	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DJ SIMMONS - PAPOOSE CANYON	07DO0294	-1049.315	-189.737	0.00	14.50	0.00	0.00	0.51	30.08	294.11
DJ SIMMONS - PAPOOSE CANYON	07DO0294	-1049.315	-189.737	0.00	14.54	0.00	0.00	0.00	0.00	0.00
DJ SIMMONS - PAPOOSE CANYON	07DO0294	-1049.315	-189.737	0.00	0.00	0.10	0.00	0.51	30.08	294.11
DJ SIMMONS - PAPOOSE CANYON	07DO0294	-1049.315	-189.737	0.00	0.00	0.10	0.00	0.00	0.00	0.00
DJ SIMMONS - PAPOOSE CANYON	07DO0295	-1049.315	-189.737	0.00	14.50	0.00	0.00	0.15	83.27	995.78
DJ SIMMONS - PAPOOSE CANYON	07DO0295	-1049.315	-189.737	0.00	14.50	0.00	0.00	0.00	0.00	0.00
DJ SIMMONS - PAPOOSE CANYON	07DO0295	-1049.315	-189.737	0.00	0.00	0.10	0.00	0.15	83.27	995.78
DJ SIMMONS - PAPOOSE CANYON	07DO0295	-1049.315	-189.737	0.00	0.00	0.10	0.00	0.00	0.00	0.00
DJ SIMMONS - PAPOOSE CANYON	07DO0295	-1041.139	-177.633	0.00	0.00	0.01	0.00	0.00	0.00	0.00
DJ SIMMONS - PAPOOSE CANYON	07DO0295	-1041.139	-177.633	0.00	0.00	0.05	0.00	0.00	0.00	0.00
QUESTAR EXPLORATION - SPARGO NO 2	07DO0361	-1051.958	-197.087	0.00	36.60	0.05	3.35	0.51	41.24	830.22
AMERICAN GYPSUM COMPANY	02EA0239	-848.135	8.838	1.20	13.10	0.50	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	91EA521F	-839.035	6.546	0.00	0.00	7.28	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	07EA0162	-839.035	6.546	5.80	5.50	2.40	0.00	0.51	30.08	295.22
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	07EA0162	-839.035	6.546	0.00	0.00	0.44	0.00	0.00	0.00	0.00
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	07EA0162	-839.035	6.546	0.00	0.00	2.16	0.00	0.00	0.00	0.00
LAFARGE WEST INC. - EAGLE WEST PIT	12EA950F	-838.726	6.76	0.00	0.00	25.66	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - GYPSUM RANCH	02EA0256	-844.283	7.208	0.00	0.00	0.78	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - GYPSUM RANCH	02EA0256	-844.283	7.208	0.00	0.00	0.77	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	98EA0610F	-857.686	11.53	0.00	0.00	0.42	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	98EA0610F	-857.686	11.53	0.00	0.00	3.48	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	06EA1183	-857.686	11.53	0.00	0.00	0.19	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP INC. DBA B&B EXCAVAT	06EA1183	-857.686	11.53	2.37	29.52	1.71	0.00	0.51	30.08	294.11
VAIL ASSOCIATES - BEAVER CREEK	03EA0114	-808.348	-0.109	0.00	0.28	0.02	0.00	0.51	30.08	294.11
VAIL ASSOCIATES - BEAVER CREEK	03EA0114	-808.348	-0.109	0.00	0.33	0.02	0.00	0.51	30.08	294.11
VAIL ASSOCIATES - BEAVER CREEK	03EA0114	-808.348	-0.109	0.00	0.33	0.02	0.00	0.51	30.08	294.11
EVERETT FAMILY FUNERAL HOME & CREMATORY	04EA1320	-845.364	6.334	0.20	0.33	0.58	5.49	0.52	7.04	854.11
EVERETT FAMILY FUNERAL HOME & CREMATORY	04EA1321	-845.364	6.334	0.23	0.28	0.66	5.49	0.52	7.96	854.11
LAFARGE WEST INC.- MINTURN CONCRETE PLT	05EA0700	-802.906	-6.287	0.00	0.00	1.28	0.00	0.51	30.08	294.11
LAFARGE WEST INC.- MINTURN CONCRETE PLT	05EA0700	-802.906	-6.287	0.00	0.00	4.02	0.00	0.51	30.08	294.11
MCCLANE CANYON MINE	99GA0682F	-1004.759	3.522	0.00	0.00	1.60	0.00	0.51	30.08	294.11
MCCLANE CANYON MINE	99GA0682F	-1004.759	3.522	0.00	0.00	0.02	0.00	0.51	30.08	294.11
MCCLANE CANYON MINE	99GA0683	-1004.759	3.522	0.00	0.00	0.48	0.00	0.51	30.08	295.22
MCCLANE CANYON MINE	99GA0684	-1004.759	3.522	0.00	0.00	0.23	0.00	0.51	30.08	295.22
MCCLANE CANYON MINE	03GA0961F	-1004.759	3.522	0.00	0.00	7.31	0.00	0.51	30.08	294.11
MCCLANE CANYON MINE	07GA0985F	-1004.759	3.522	0.00	0.00	0.86	0.00	0.51	30.08	294.11
GRANT BROS CONST	13GA318-3F	-913.517	3.09	0.00	0.00	1.79	0.00	0.51	30.08	294.11
GRANT BROS CONST	13GA318-2	-913.517	3.09	0.00	0.00	0.01	0.00	0.51	30.08	633.80
GRANT BROS CONST	13GA318-2	-913.517	3.09	0.00	0.00	0.50	0.00	0.51	30.08	633.80
GRANT BROS CONST	13GA318-2	-913.517	3.09	0.00	0.00	0.16	0.00	0.51	30.08	633.80
GRANT BROS CONST	13GA318-2	-913.517	3.09	0.00	0.00	0.16	0.00	0.51	30.08	633.80
GRANT BROS CONST	13GA318-2	-913.517	3.09	0.00	0.00	0.09	0.00	0.51	30.08	633.80
VALLEY VIEW HOSPITAL	03GA0294	-880.716	-1.369	0.05	7.18	0.51	6.40	0.40	23.44	505.22
VALLEY VIEW HOSPITAL	06GA1382	-880.716	-1.369	0.04	6.00	0.46	9.14	0.52	23.47	505.22
VALLEY VIEW HOSPITAL	06GA1382	-880.716	-1.369	12.78	1.80	0.18	9.14	0.52	23.47	505.22
TRI-STATE GENERATION & TRANS.-RIFLE STAT	85GA185-1	-915.509	0.865	0.00	24.65	0.00	16.76	3.44	31.18	360.78
TRI-STATE GENERATION & TRANS.-RIFLE STAT	85GA185-1	-915.509	0.865	0.00	0.00	3.34	16.76	3.44	31.18	360.78
TRI-STATE GENERATION & TRANS.-RIFLE STAT	85GA185-1	-915.509	0.865	0.08	0.00	0.00	16.76	3.44	31.18	360.78
TRI-STATE GENERATION & TRANS.-RIFLE STAT	87GA261	-915.509	0.865	0.00	0.04	0.00	6.10	0.21	51.82	838.56

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
TRI-STATE GENERATION & TRANS.-RIFLE STAT		-915.509	0.865	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TRI-STATE GENERATION & TRANS.-RIFLE STAT	85GA185-1	-915.509	0.865	0.08	24.49	3.26	16.76	3.44	30.08	360.78
TRI-STATE GENERATION & TRANS.-RIFLE STAT		-915.509	0.865	0.08	24.91	3.51	16.76	3.44	30.08	360.78
EVERGREEN OP CORP - MEAD 23-44 CS	01GA0546	-925.986	0.931	0.00	0.00	-0.08	2.44	0.13	24.23	633.80
ETC CANYON PIPELINE - RIFLE C.S.	02GA0719	-923.852	3.328	0.00	66.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE - RIFLE C.S.	02GA0719	-923.852	3.328	0.00	66.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE - RIFLE C.S.	02GA0719	-923.852	3.328	0.00	0.00	0.18	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE - RIFLE C.S.	02GA0719	-923.852	3.328	0.00	0.00	0.18	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE - RIFLE C.S.	02GA0719	-923.852	3.328	0.01	0.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE - RIFLE C.S.	02GA0719	-923.852	3.328	0.01	0.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE - RIFLE C.S.	08GA0254	-923.852	3.328	0.03	29.50	0.52	6.40	0.51	46.24	699.67
SOURCEGAS DBA ROCKY MTN- CRYSTAL RIVER	90GA108-1	-878.356	-17.612	0.00	-6.21	0.05	9.14	0.24	60.56	727.44
SOURCEGAS DBA ROCKY MTN- CRYSTAL RIVER	90GA108-2	-878.356	-17.612	0.00	9.71	0.00	6.10	0.31	31.88	688.56
SOURCEGAS DBA ROCKY MTN- CRYSTAL RIVER	90GA108-2	-878.356	-17.612	0.00	0.00	0.42	6.10	0.31	31.88	688.56
SOURCEGAS DBA ROCKY MTN- CRYSTAL RIVER	90GA108-2	-878.356	-17.612	0.01	0.00	0.00	6.10	0.31	31.88	688.56
SAVAGE INDUSTRIES INC	91GA394	-926.214	1.731	0.00	0.00	4.43	11.58	0.38	30.08	349.67
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	15.10	0.00	6.10	0.46	15.82	541.33
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	0.00	0.25	6.10	0.46	15.82	541.33
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.02	0.00	0.00	6.10	0.46	15.82	541.33
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	15.10	0.00	6.10	0.46	15.82	541.33
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	0.00	0.25	6.10	0.46	15.82	541.33
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.02	0.00	0.00	6.10	0.46	15.82	541.33
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	13.00	0.00	6.71	0.36	12.59	521.89
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	0.00	0.11	6.71	0.36	12.59	521.89
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.01	0.00	0.00	6.71	0.36	12.59	521.89
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	17.80	0.00	6.40	0.41	23.35	721.89
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.00	0.00	0.36	6.40	0.41	23.35	721.89
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.02	0.00	0.00	6.40	0.41	23.35	721.89
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.02	17.80	0.36	6.40	0.41	23.35	721.89
WILLIAMS PRODUCTION RMT - WASATCH YARD	02GA0670	-939.651	-0.591	0.02	17.80	0.36	6.40	0.41	23.35	721.89
LAFARGE WEST INC. - POWERS PIT	92GA1506F	-871.137	-15.589	0.00	0.00	10.02	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - POWERS PIT	92GA1506F	-871.137	-15.589	0.00	0.00	13.05	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - POWERS PIT	05GA0469	-871.137	-15.589	0.20	14.00	1.00	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - POWERS PIT	07GA0972	-871.137	-15.589	0.00	0.00	1.50	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - POWERS PIT	07GA0972	-871.137	-15.589	0.00	0.00	1.50	0.00	0.51	30.08	294.11
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	-6.60	0.01	6.10	0.46	15.82	541.33
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	4.90	0.01	7.32	0.25	24.93	521.89
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	4.90	0.01	7.32	0.25	24.93	521.89
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	4.90	0.00	7.32	0.25	24.93	521.89
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	14.80	0.00	5.79	0.20	148.53	727.44
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	0.00	0.26	5.79	0.20	148.53	727.44
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.02	0.00	0.00	5.79	0.20	148.53	727.44
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	0.10	0.00	6.10	0.10	30.08	810.78
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	13.80	0.00	7.32	0.46	17.62	525.22
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	0.00	0.22	7.32	0.46	17.62	525.22
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.01	0.00	0.00	7.32	0.46	17.62	525.22
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	4.60	0.00	7.32	0.46	17.62	525.22
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.00	0.00	0.00	6.10	0.10	30.08	810.78
BARGATH INC-GRAND VALLEY	02GA1018	-947.259	10.077	0.40	5.00	0.10	4.57	0.31	144.08	533.00
PUBLIC SERVICE CO - RIFLE GAS PLANT	94GA279-1	-924.562	2.781	-0.01	-2.86	0.16	6.10	0.24	30.48	633.80
PUBLIC SERVICE CO - RIFLE GAS PLANT	94GA279-2	-924.562	2.781	0.00	-0.60	0.26	6.10	0.24	30.48	633.80
PUBLIC SERVICE CO - RIFLE GAS PLANT	02GA0535	-924.562	2.781	0.00	4.00	0.05	12.19	0.36	31.03	880.22
PUBLIC SERVICE CO - RIFLE GAS PLANT	04GA0958	-924.562	2.781	0.00	0.40	0.01	12.19	0.36	31.03	880.22
BARGATH INC - RIFLE STATION		-923.867	3.343	0.00	2.80	0.00	4.57	0.15	54.44	533.00
BILL BARRETT CORP - MAMM CREEK CS	06GA0062	-914.11	-2.137	0.00	4.93	0.00	0.00	0.00	0.00	0.00
ENCANA OIL & GAS (USA) INC.	95GA909-1	-958.09	14.371	0.00	0.09	0.01	4.57	0.34	6.95	563.56
ENCANA OIL & GAS (USA) INC.	03GA0966	-958.09	14.371	0.00	0.00	0.00	0.00	0.51	30.08	294.11
BARGATH INC.- ROAN CLIFF	97GA0265	-945.495	-0.939	0.00	0.10	-1.46	7.01	0.51	59.74	721.89
BARGATH INC.- ROAN CLIFF	97GA0265	-945.495	-0.939	0.00	0.00	0.00	4.88	0.25	22.10	894.11
BARGATH INC.- ROAN CLIFF	97GA0265	-945.495	-0.939	0.02	22.20	0.36	10.67	0.25	69.71	721.89
BARGATH INC.- ROAN CLIFF		-945.495	-0.939	0.02	22.20	0.36	10.67	0.25	69.71	721.89
WILLIAMS PRODUCTION RMT - STARKEY GULCH	02GA1066	-950.22	0.877	0.00	26.10	0.00	8.23	0.46	13.72	616.33
WILLIAMS PRODUCTION RMT - STARKEY GULCH	02GA1066	-950.22	0.877	0.00	0.00	0.42	8.23	0.46	13.72	616.33
WILLIAMS PRODUCTION RMT - STARKEY GULCH	02GA1066	-950.22	0.877	0.03	0.00	0.00	8.23	0.46	13.72	616.33
WILLIAMS PRODUCTION RMT - STARKEY GULCH	02GA1066	-950.22	0.877	0.02	16.60	0.38	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT - STARKEY GULCH	02GA1066	-950.22	0.877	0.02	16.60	0.38	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT - STARKEY GULCH	02GA1066	-950.22	0.877	0.02	17.50	0.40	7.01	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT - STARKEY GULCH	02GA1066	-950.22	0.877	0.02	17.50	0.40	6.10	0.31	49.68	730.22
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.30	73.90	0.00	0.00	0.51	30.08	294.11
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	7.40	42.67	1.83	15.24	449.67
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	7.20	12.19	0.50	18.50	299.67
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	3.94	12.19	0.50	18.50	299.67
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	4.58	12.19	0.50	18.50	299.67
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.05	3.80	0.55	9.14	0.46	71.87	449.67
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.05	0.00	9.14	0.15	114.21	824.67
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	0.40	10.67	0.24	12.95	294.11
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	1.80	38.71	0.55	13.99	302.44
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	0.58	22.86	0.37	13.47	299.67
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	2.10	27.43	0.61	12.92	296.89
AMERICAN SODA LLP - PARACHUTE FACILITY	98GA0858	-946.236	0.424	0.00	0.00	0.43	24.38	0.37	11.22	296.89
AMERICAN SODA LLP - PARACHUTE FACILITY		-946.236	0.424	0.00	0.00	0.51	39.62	0.20	191.45	368.56
AMERICAN SODA LLP - PARACHUTE FACILITY		-946.236	0.424	0.00	0.00	1.02	39.62	0.25	70.01	365.78
FLAG SAND & GRAVEL PIT	05GA0693F	-907.169	2.506	0.00	0.00	0.06	0.00	0.51	30.08	294.11
FLAG SAND & GRAVEL PIT	05GA0693F	-907.169	2.506	0.00	0.00	6.36	0.00	0.51	30.08	294.11
OXY USA WTP LP -CASCADE CREEK COMPRESSOR	04GA1274	-959.13	9.617	0.01	39.90	0.08	3.05	1.52	0.31	633.80
OXY USA WTP LP -CASCADE CREEK COMPRESSOR	06GA0503	-959.13	9.617	0.00	1.80	0.00	2.44	0.15	17.37	829.67
OXY USA WTP LP -CASCADE CREEK COMPRESSOR	06GA0504	-959.13	9.617	0.00	1.80	0.00	2.44	0.15	17.37	829.67
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.00	16.60	0.00	6.40	0.31	47.76	633.80
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.00	0.00	0.38	6.40	0.31	47.76	633.80
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.02	0.00	0.00	6.40	0.31	47.76	633.80
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.00	24.40	0.00	6.40	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.00	17.50	0.00	6.40	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.00	0.00	0.44	6.40	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.00	0.00	0.40	6.40	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.03	0.00	0.00	6.40	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.02	0.00	0.00	6.40	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.02	15.20	0.40	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.02	15.20	0.40	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.02	17.50	0.40	6.10	0.31	49.68	730.22

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
WILLIAMS PRODUCTION RMT CO. - SHARRARD	02GA0443	-929.753	1.555	0.02	15.20	0.40	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	16.60	0.00	7.32	0.31	49.71	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.38	2.74	0.31	49.71	633.80
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.38	7.32	0.31	49.71	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	2.74	0.31	49.71	633.80
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	7.32	0.31	49.71	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	16.60	0.00	2.74	0.31	49.71	633.80
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	16.60	0.00	7.32	0.31	49.71	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.38	2.74	0.31	49.71	633.80
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.38	7.32	0.31	49.71	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	2.74	0.31	49.71	633.80
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	7.32	0.31	49.71	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	16.60	0.00	7.01	0.31	46.42	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	16.60	0.00	7.01	0.31	46.42	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.38	7.01	0.31	46.42	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.38	7.01	0.31	46.42	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	7.01	0.31	46.42	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	7.01	0.31	46.42	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	16.60	0.00	7.01	0.31	106.31	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	15.20	0.00	7.01	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.38	7.01	0.31	106.31	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.40	7.01	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	7.01	0.31	106.31	738.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	7.01	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	17.50	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	15.20	0.00	7.01	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.40	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.00	0.00	0.40	7.01	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-943.59	-2.036	0.02	15.20	0.40	7.01	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT CO. -HAYES GULCH	02GA1067	-945.788	-0.701	0.00	28.80	0.00	0.00	0.00	0.00	0.00
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	28.80	0.00	0.00	0.31	60.75	633.80
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	0.00	0.83	0.00	0.00	0.00	0.00
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	0.00	0.83	0.00	0.31	60.75	633.80
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.05	0.00	0.00	0.00	0.00	0.00	0.00
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.05	0.00	0.00	0.00	0.31	60.75	633.80
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	10.00	0.00	4.27	0.31	46.88	727.44
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	0.00	0.16	4.27	0.31	46.88	727.44
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.01	0.00	0.00	4.27	0.31	46.88	727.44
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	1.80	0.00	3.05	0.06	84.98	727.44
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	0.00	0.00	3.05	0.06	84.98	727.44
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.00	0.00	0.00	3.05	0.06	84.98	727.44
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.01	11.60	0.87	5.18	0.31	0.67	796.89
BARGATH INC - HAYBARN	02GA0442	-945.788	-0.701	0.03	14.40	0.42	6.71	0.31	58.37	730.22
WILLIAMS PRODUCTION RMT CO - WEBSTER CS	04GA0021	-937.051	-0.435	0.00	22.10	0.00	6.10	0.31	49.68	730.22
ENCANA - EAST MAMM CREEK CS	03GA0539	-915.464	-2.594	0.04	1.69	0.69	12.19	0.61	18.81	633.80
ENCANA - EAST MAMM CREEK CS	04GA0052	-915.464	-2.594	0.06	20.48	0.94	61.27	1.52	67.45	727.44
ENCANA - EAST MAMM CREEK CS	04GA0354	-915.464	-2.594	0.08	30.55	1.37	15.24	0.41	51.51	633.80
ENCANA - EAST MAMM CREEK CS	04GA0355	-915.464	-2.594	0.08	30.53	1.37	15.24	0.41	51.51	633.80
LAFARGE WEST - MAMM CREEK PIT	01GA0979F	-915.699	2.63	0.00	0.00	0.20	0.00	0.51	30.08	294.11
LAFARGE WEST - MAMM CREEK PIT	01GA0979F	-915.699	2.63	0.00	0.00	0.10	0.00	0.51	30.08	294.11
LAFARGE WEST - MAMM CREEK PIT	01GA0979F	-915.699	2.63	0.00	0.00	4.45	0.00	0.51	30.08	294.11
ENCANA OIL & GAS (USA) INC. - GASAWAY	05GA0734	-982.305	7.803	0.00	19.40	0.00	7.62	0.31	30.08	755.22
ENCANA OIL & GAS - HUNTER MESA	02GA0231	-915.063	-4.648	0.00	14.10	0.00	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0231	-915.063	-4.648	0.00	21.20	0.00	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0231	-915.063	-4.648	0.00	0.00	0.06	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0231	-915.063	-4.648	0.07	0.00	0.11	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0232	-915.063	-4.648	0.00	14.40	0.00	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0232	-915.063	-4.648	0.00	23.70	0.00	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0232	-915.063	-4.648	0.00	0.00	0.06	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0232	-915.063	-4.648	0.07	0.00	0.11	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0233	-915.063	-4.648	0.00	14.10	0.00	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0233	-915.063	-4.648	0.00	19.82	0.00	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0233	-915.063	-4.648	0.00	0.00	0.06	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0233	-915.063	-4.648	0.07	0.00	0.11	7.62	4.95	22.40	721.89
ENCANA OIL & GAS - HUNTER MESA	02GA0944	-915.063	-4.648	0.06	13.61	1.02	6.10	0.46	67.45	633.80
ENCANA OIL & GAS - HUNTER MESA	02GA0944	-915.063	-4.648	0.00	2.50	0.00	0.00	0.00	0.00	0.00
ENCANA OIL & GAS (USA) INC. - PUMBA	02GA0236	-918.462	-4.811	0.03	1.95	0.42	7.62	9.91	22.40	633.80
ENCANA OIL & GAS (USA) INC. - PUMBA	02GA0236	-918.462	-4.811	0.00	0.80	0.00	0.00	0.00	0.00	0.00
ENCANA OIL & GAS (USA) INC. - PUMBA	02GA0557	-918.462	-4.811	0.09	30.10	1.55	6.71	4.88	0.76	633.80
ENCANA OIL & GAS (USA) INC. - PUMBA	03GA0341	-918.462	-4.811	0.08	29.60	1.37	7.62	0.46	51.51	733.00
ENCANA OIL & GAS (USA) INC. - PUMBA	03GA0342	-918.462	-4.811	0.08	30.84	1.37	7.62	0.41	51.51	734.11
ENCANA GATHERING - MAMM CREEK CONDITIONI	03GA0447	-924.358	2.912	0.00	2.70	0.00	10.67	0.31	46.73	810.78
ENCANA GATHERING - MAMM CREEK CONDITIONI	03GA0935	-924.358	2.912	2.50	20.27	1.66	6.10	0.46	67.45	633.80
ENCANA GATHERING - MAMM CREEK CONDITIONI	03GA0939	-924.358	2.912	0.02	0.10	0.10	3.66	0.15	25.91	633.80
ENCANA GATHERING - MAMM CREEK CONDITIONI	04GA1352	-924.358	2.912	0.00	2.00	0.00	0.00	0.51	30.08	294.11
ENCANA GATHERING - MAMM CREEK CONDITIONI	05GA0883	-924.358	2.912	0.00	1.21	0.66	10.67	0.31	46.73	810.78
HALLIBURTON ENERGY SVCS	08GA0189	-943.672	-2.918	0.05	1.28	0.02	1.22	0.05	30.08	294.11
ENCANA C15		-919.222	-6.138	0.00	0.00	0.00	0.00	0.51	30.08	294.11
ENCANA C15		-919.222	-6.138	0.00	0.03	0.00	0.00	0.00	0.00	0.00
ENCANA - G33		-910.791	-2.939	0.00	0.08	0.00	6.10	0.61	3.05	644.11
ENCANA - B36		-915.226	-2.449	0.00	0.04	0.00	6.10	0.61	3.05	644.11
ENCANA - F10	04GA0014	-919.076	-4.941	0.00	0.00	0.00	6.10	0.61	3.05	644.11
ENCANA - F10	04GA0014	-919.076	-4.941	0.00	0.00	0.00	6.10	0.61	3.05	644.11
ENCANA - F10	04GA0014	-913.865	-2.588	0.00	0.13	0.00	0.00	0.00	0.00	0.00
ENCANA - F10	04GA0014	-911.229	-3.296	0.00	0.02	0.00	0.00	0.00	0.00	0.00
ENCANA - F10	04GA0014	-911.229	-3.296	0.00	0.03	0.00	0.00	0.00	0.00	0.00
ENCANA - F33		-911.229	-3.296	0.00	0.10	0.00	6.10	0.61	3.05	644.11
WILLIAMS - TRAIL RIDGE COMP STATION	03GA0594	-958.786	14.605	0.00	19.40	0.07	0.00	0.51	30.08	294.11
PETROLEUM DEVELOPMENT - GARDEN GULCH	07GA0042	-949.538	7.121	0.04	8.20	0.66	6.10	0.35	38.10	810.78
PETROLEUM DEVELOPMENT - GARDEN GULCH	08GA0232	-949.538	7.121	0.01	9.46	0.17	6.10	0.44	19.78	541.33
ENCANA (WEST) - HAY CANYON	03GA1019	-1003.111	9.764	0.01	15.54	0.10	2.44	0.15	38.71	633.80
ENCANA (WEST) - HAY CANYON	03GA1019	-912.07	-10.882	0.00	0.22	0.00	0.00	0.00	0.00	0.00
ENCANA - P3		-912.07	-10.882	0.00	0.02	0.00	6.10	0.61	3.05	644.11
ENCANA - P3		-919.348	-3.188	0.00	0.02	0.00	0.00	0.00	0.00	0.00
ENCANA - N34		-919.348	-3.188	0.00	0.08	0.00	6.10	0.61	3.05	644.11
ENCANA - M3A	03GA0870	-919.389	-4.161	0.00	0.26	0.00	6.10	0.61	3.05	644.11
ENCANA - M3A	03GA0870	-919.759	-3.135	0.00	0.20	0.00	0.00	0.00	0.00	0.00
NATIONAL FUEL CORP. - BAXTER FACILITY	03GA1077	-1023.284	0.651	0.01	18.50	0.08	57.91	3.66	49.23	516.33

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
NATIONAL FUEL CORP. - BAXTER FACILITY	03GA1077	-920.579	-3.567	0.00	0.05	0.00	0.00	0.00	0.00	0.00
ENCANA - K4B	03GA1142	-920.579	-3.567	0.00	0.22	0.00	6.10	0.61	3.05	644.11
ENCANA - K4B	03GA1142	-909.67	-3.864	0.00	0.09	0.00	0.00	0.00	0.00	0.00
ENCANA - L34		-909.67	-3.864	0.00	0.17	0.00	6.10	0.61	3.05	644.11
ENCANA - L34		-909.67	-3.864	0.00	0.08	0.00	0.00	0.00	0.00	0.00
ENCANA - L34		-947.627	0.373	0.00	14.40	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	14.40	0.00	0.00	6.71	46.48	738.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.38	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.38	0.00	6.71	46.48	738.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	0.00	6.71	46.48	738.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	14.10	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	14.10	0.00	6.71	0.31	46.48	738.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.38	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.38	6.71	0.31	46.48	738.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	6.71	0.31	46.48	738.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	14.40	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	15.20	0.00	6.71	0.31	49.71	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.38	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.40	6.71	0.31	49.71	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	6.71	0.31	49.71	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	14.40	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	15.20	0.00	6.71	0.31	49.68	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.38	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.40	6.71	0.31	49.68	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	6.71	0.31	49.68	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	14.40	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	15.20	0.00	6.71	0.31	49.68	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.38	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.00	0.00	0.40	6.71	0.31	49.68	730.22
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT - RILEY CS	04GA0009	-947.627	0.373	0.02	15.20	0.40	6.71	0.31	49.71	730.22
WILLIAMS PROD RMT ANVIL POINTS CS	04GA0011	-931.675	2.185	0.04	14.40	0.40	8.53	0.31	49.71	730.22
WILLIAMS PROD RMT ANVIL POINTS CS	04GA0011	-931.675	2.185	0.04	14.40	0.40	8.53	0.31	49.71	730.22
WILLIAMS PROD RMT ANVIL POINTS CS	04GA0011	-931.675	2.185	0.02	15.20	0.40	6.71	0.31	49.71	730.22
WILLIAMS PROD RMT ANVIL POINTS CS	04GA0011	-931.675	2.185	0.02	15.20	0.40	8.53	0.31	49.68	730.22
WILLIAMS PROD RMT ANVIL POINTS CS	04GA0011	-931.675	2.185	0.02	15.20	0.40	8.53	0.31	49.68	730.22
WILLIAMS PROD RMT ANVIL POINTS CS		-931.675	2.185	0.02	15.20	0.40	8.53	0.31	49.68	730.22
GRAND JUNCTION PIPE & SUPPLY - UNA PIT	04GA0105F	-948.792	-8.295	0.00	0.00	0.10	0.00	0.51	30.08	294.11
GRAND JUNCTION PIPE & SUPPLY - UNA PIT	04GA0105F	-948.792	-8.295	0.00	0.00	14.60	0.00	0.51	30.08	294.11
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-937.179	-0.013	0.02	22.10	0.38	6.10	0.31	49.68	730.22
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-937.179	-0.013	0.02	22.10	0.38	6.10	0.31	49.71	730.22
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-937.179	-0.013	0.02	22.10	0.38	6.10	0.31	49.71	730.22
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-937.179	-0.013	0.02	22.10	0.38	6.10	0.31	49.68	730.22
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-937.179	-0.013	0.02	22.10	0.38	6.10	0.31	49.68	730.22
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-937.179	-0.013	0.02	22.10	0.38	6.10	0.31	49.68	730.22
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-920.582	-3.563	0.00	0.07	0.00	0.00	0.00	0.00	0.00
WILLIAMS PROD RMT CO. - COTTONWOOD POINT	04GA0119	-920.582	-3.563	0.00	0.03	0.00	0.00	0.00	0.00	0.00
ENCANA - K4C	04GA0172	-920.582	-3.563	0.00	0.21	0.00	6.10	0.61	3.05	644.11
ENCANA (WEST) - LOGAN WASH AMINE PLANT	04GA0827	-962.117	-6.518	0.00	6.30	0.00	0.00	0.51	30.08	294.11
ENCANA (WEST) - LOGAN WASH AMINE PLANT	06GA0261	-962.117	-6.518	0.00	6.20	0.00	6.10	0.31	30.08	699.67
ENCANA (WEST) - DIVIDE CREEK 31	04GA0941	-902.79	-16.548	0.00	4.30	0.01	1.83	0.06	30.48	435.78
WILLIAMS PRODUCTION RMT - RULISON CS	04GA0976	-949.833	2.665	0.00	6.30	0.05	5.79	0.35	6.22	510.78
WILLIAMS PRODUCTION RMT - RULISON CS	04GA0976	-949.833	2.665	0.03	26.10	0.44	8.53	0.51	36.64	588.56
WILLIAMS PRODUCTION RMT - RULISON CS	04GA0976	-949.833	2.665	0.03	26.10	0.44	8.53	0.51	36.64	588.56
WILLIAMS PRODUCTION RMT - RULISON CS	04GA0976	-949.833	2.665	0.02	16.60	0.38	6.10	0.31	57.97	730.22
WILLIAMS PRODUCTION RMT - RULISON CS	04GA0976	-949.833	2.665	0.02	15.20	0.35	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - RULISON CS	04GA0976	-949.833	2.665	0.02	15.20	0.40	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT - RULISON CS	04GA0976	-949.833	2.665	0.02	15.20	0.40	6.10	0.31	49.68	730.22
WILLIAMS PROD RMT-SOUTH GRAND VALEY CS	04GA1037	-946.015	-5.001	0.02	15.20	0.40	6.71	0.36	26.61	710.78
WILLIAMS PROD RMT-SOUTH GRAND VALEY CS	04GA1037	-946.015	-5.001	0.00	15.20	0.00	6.10	0.31	49.71	730.22
OLDCASTLE DBA UNITED CO -GLEN'S PIT	04GA1277F	-917.714	2.767	0.00	0.00	3.60	0.00	0.51	30.08	294.11
OLDCASTLE DBA UNITED CO -GLEN'S PIT	04GA1277F	-917.714	2.767	0.00	0.00	0.05	0.00	0.51	30.08	294.11
ENCANA - J34NW	05GA0645	-918.506	-2.873	0.00	0.12	0.00	6.10	0.61	3.05	644.11
ENCANA (WEST) - DIVIDE CREEK 25-2C	04GA1306	-906.822	-10.645	1.05	7.84	1.08	2.74	0.09	30.08	833.00
ENCANA - D27NW		-919.012	-0.454	0.00	0.14	0.00	6.10	0.61	3.05	644.11
ENCANA - D27NW		-919.012	-0.454	0.00	0.01	0.00	0.00	0.00	0.00	0.00
ENCANA - D27NW		-908.539	-4.836	0.00	0.19	0.00	0.00	0.00	0.00	0.00
BILL BARRETT CORP - TANK BATTERY # 16816		-911.095	-2.089	0.00	0.06	0.00	6.10	0.61	3.05	644.11
ENCANA - C9W		-920.631	-4.36	0.00	0.10	0.00	6.10	0.61	3.05	644.11
ENCANA - C9W		-910.119	-4.195	0.00	0.12	0.00	0.00	0.00	0.00	0.00
ENCANA - M34NE	05GA0643	-910.119	-4.195	0.00	0.36	0.00	6.10	0.61	3.05	644.11
ENCANA (WEST) - K29NE		-912.677	-1.925	0.00	0.03	0.00	6.10	0.61	3.05	644.11
ENCANA (WEST) - K29NE		-910.505	-4.163	0.00	0.08	0.00	0.00	0.00	0.00	0.00
ENCANA - P33NE	05GA0647	-910.505	-4.163	0.00	0.18	0.00	6.10	0.61	3.05	644.11
OXY USA WTP LP - CONN CREEK GAS	05GA0067	-960.162	2.406	0.03	8.08	0.42	10.36	0.31	55.63	733.00
OXY USA WTP LP - CONN CREEK GAS	05GA0068	-960.162	2.406	0.03	39.45	0.51	6.10	0.24	49.53	633.80
OXY USA WTP LP - CONN CREEK GAS	05GA0072	-960.162	2.406	0.00	6.10	0.00	0.00	0.51	30.08	295.22
OXY USA WTP LP - CONN CREEK GAS	05GA0174	-960.162	2.406	0.03	8.36	0.42	10.36	0.31	55.63	733.00
OXY USA WTP LP - CONN CREEK GAS	05GA0175	-960.162	2.406	0.03	8.23	0.42	10.36	0.31	55.63	733.00
OXY USA WTP LP - CONN CREEK GAS	05GA0176	-960.162	2.406	0.03	7.36	0.42	0.00	0.51	30.08	733.00
WILLIAMS PRODUCTION RMT - CALLAHAN	05GA0073	-946.59	-0.951	0.02	17.00	0.39	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - CALLAHAN	05GA0073	-946.59	-0.951	0.02	17.00	0.40	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - CALLAHAN	05GA0073	-946.59	-0.951	0.02	17.00	0.40	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - CALLAHAN	05GA0073	-929.207	2.731	0.00	15.20	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.00	17.00	0.00	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.00	0.00	0.40	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.00	0.00	0.39	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.02	0.00	0.00	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.02	17.00	0.39	6.10	0.31	49.71	730.22
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.00	17.00	0.39	0.00	0.51	49.68	730.22
WILLIAMS PRODUCTION RMT - CLOUGH	05GA0074	-929.207	2.731	0.02	17.00	0.00	0.00	0.51	298.22	730.22
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-949.713	3.48	0.02	17.00	0.39	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-949.713	3.48	0.00	15.20	0.00	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-949.713	3.48	0.02	17.00	0.39	6.10	0.31	49.68	730.22

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-949.713	3.48	0.02	17.00	0.39	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-949.713	3.48	0.02	17.00	0.39	6.10	0.51	49.68	730.22
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-918.176	-0.126	0.00	0.17	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-918.176	-0.126	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-907.817	-5.391	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT - JANGLES	05GA0075	-918.702	-1.255	0.00	0.08	0.00	0.00	0.00	0.00	0.00
ENCANA - M27NW	05GA0642	-919.161	-1.612	0.00	0.14	0.00	6.10	0.61	3.05	644.11
ENCANA - M27NW	05GA0642	-919.161	-1.612	0.00	0.01	0.00	0.00	0.00	0.00	0.00
BARGATH INC- HYRUP PROD FACILITY		-945.798	-12.035	0.00	0.21	0.02	6.40	4.04	30.08	513.56
ENCANA (WEST) - 03ONE		-913.737	-2.153	0.00	0.01	0.00	6.10	0.61	3.05	644.11
ENCANA (WEST) - 03ONE		-909.944	-3.006	0.00	0.02	0.00	0.00	0.00	0.00	0.00
ENCANA (WEST) - 03ONE		-909.944	-3.006	0.00	0.14	0.00	0.00	0.00	0.00	0.00
WINDSOR ENERGY - CASTLE SPRINGS CENTRAL	05GA0495	-903.829	-7.981	0.02	18.30	0.25	5.18	0.21	5.09	725.78
WINDSOR ENERGY - CASTLE SPRINGS CENTRAL	05GA0496	-903.829	-7.981	0.00	9.48	0.03	0.00	0.51	30.08	294.11
WINDSOR ENERGY - CASTLE SPRINGS CENTRAL	07GA0797	-910.161	-4.628	0.00	0.28	0.00	0.00	0.00	0.00	0.00
BILL BARRETT CORP - TANK # 16885/16902	06GA0453	-905.598	-3.481	0.00	2.49	0.18	3.66	0.10	78.91	894.11
BILL BARRETT CORP - TANK # 16885/16902	06GA0453	-929.066	0.275	0.00	22.10	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	19.30	0.00	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	0.00	0.38	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	0.00	0.40	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	0.00	0.00	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	22.14	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	15.20	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	19.30	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	0.00	0.38	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	0.00	0.40	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	0.00	0.40	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	15.20	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	19.30	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	0.00	0.40	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.00	0.00	0.40	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	19.30	0.40	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	19.30	0.40	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION RMT-HEATH CS	05GA0569	-929.066	0.275	0.02	19.30	0.40	7.32	0.31	49.68	730.22
ANTERO RESOURCES II PARK B PAD	05GA0618	-912.752	3.07	0.01	2.69	0.18	35.97	0.31	45.17	730.22
ENCANA OIL & GAS - WEST FORK SHALE PIT	05GA0651F	-950.51	19.711	0.00	0.00	8.75	0.00	0.51	30.08	294.11
ANTERO RESOURCES II PARK B PAD	05GA0658	-916.118	4.081	0.00	4.60	0.00	5.49	0.31	46.54	730.22
BILL BARRETT CORP - TANK BATTERY # 20064		-909.16	-2.705	0.00	0.08	0.00	6.10	0.61	3.05	644.11
BILL BARRETT CORP - TANK BATTERY # 20730		-907.338	-0.898	0.00	0.04	0.00	6.10	0.61	3.05	644.11
BILL BARRETT CORP - TANK BATTERY # 21148		-909.206	-3.092	0.00	0.11	0.00	6.10	0.61	3.05	644.11
BILL BARRETT CORP - TANK BATTERY # 21148		-911.672	-0.026	0.00	0.06	0.00	0.00	0.00	0.00	0.00
BILL BARRETT CORP - TANK BATTERY # 21148		-911.672	-0.026	0.00	4.70	0.00	0.00	0.00	0.00	0.00
BILL BARRETT CORP - TANK BATTERY # 21360		-909.259	-3.515	0.00	0.13	0.00	6.10	0.61	3.05	644.11
WILLIAMS PRODUCTION - MC NARY	06GA0155	-926.67	2.667	0.02	22.10	0.38	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION - MC NARY	06GA0155	-926.67	2.667	0.02	22.10	0.38	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION - WHEELER GULCH	06GA0156	-946.924	1.555	0.00	19.30	0.40	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION - WHEELER GULCH	06GA0156	-946.924	1.555	0.00	19.30	0.30	6.10	0.31	49.68	730.22
WILLIAMS PRODUCTION - WHEELER GULCH	06GA0156	-946.924	1.555	0.02	19.30	0.40	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION - WHEELER GULCH	06GA0156	-946.924	1.555	0.02	19.30	0.40	7.32	0.51	49.68	730.22
WILLIAMS PRODUCTION - WHEELER GULCH	06GA0156	-946.924	1.555	0.02	19.30	0.40	7.32	0.31	49.68	730.22
WILLIAMS PRODUCTION - WHEELER GULCH	06GA0156	-946.924	1.555	0.00	19.30	0.00	0.00	0.00	0.00	0.00
M-I SWACO - RIFLE FACILITY	06GA0198	-924.934	2.481	0.00	0.00	0.14	0.00	0.51	30.08	295.22
M-I SWACO - RIFLE FACILITY	06GA0198	-924.934	2.481	0.00	0.00	0.30	0.00	0.51	30.08	295.22
CHEVRON USA INC	06GA0204	-966.833	12.331	0.00	12.80	0.00	3.05	0.31	30.08	710.78
BILL BARRETT CORP - TANK BATTERY # 21473		-909.436	-1.468	0.00	0.03	0.00	6.10	0.61	3.05	644.11
BILL BARRETT CORP - TANK BATTERY # 21473		-921.065	-4.714	0.00	0.27	0.00	0.00	0.00	0.00	0.00
BILL BARRETT CORP - TANK BATTERY # 21473		-905.97	-3.466	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BILL BARRETT CORP - TANK BATTERY # 22358		-908.581	-1.184	0.00	0.09	0.00	6.10	0.61	3.05	644.11
BILL BARRETT CORP - TANK BATTERY # 22430		-908.18	-1.213	0.00	0.07	0.00	6.10	0.61	3.05	644.11
WINDSOR ENERGY GROUP - PAD T	07GA1167	-903.473	-8.413	0.00	10.20	0.04	2.13	0.08	30.48	394.11
BILL BARRETT CORP - TANK BATTERY # 22682		-908.991	-5.056	0.00	0.06	0.00	6.10	0.61	3.05	644.11
BILL BARRETT CORP - TANK # 23140		-910.194	-1.384	0.00	0.06	0.00	6.10	0.61	3.05	644.11
BILL BARRETT CORP - # 22528		-908.62	-1.577	0.00	0.07	0.00	6.10	0.61	3.05	644.11
ENCANA (WEST)-WALLACE CREEK COMP STATION	06GA0808	-948.658	-10.407	0.00	0.30	0.00	0.00	0.51	30.08	294.11
BILL BARRETT CORPORATION 26255		-910.059	-0.189	0.00	0.04	0.00	6.10	0.61	3.05	644.11
LARAMIE ENERGY - HOOKER PAD		-923.008	0.032	0.00	0.05	0.00	6.10	0.87	2.44	337.44
LARAMIE ENERGY - HOOKER PAD		-908.464	-3.978	0.00	0.31	0.00	0.00	0.00	0.00	0.00
LARAMIE ENERGY - HOOKER PAD		-908.464	-3.978	0.00	8.17	0.00	0.00	0.00	0.00	0.00
BILL BARRETT CORP - BATTERY# 16907		-911.136	-2.483	0.00	0.21	0.00	6.10	0.61	3.05	644.11
WILLIAMS PRODUCTION-WEBSTER HILL COMP ST	06GA1279	-926.742	2.807	0.06	24.00	1.01	8.53	0.46	67.45	731.89
WILLIAMS PRODUCTION-WEBSTER HILL COMP ST	06GA1279	-926.742	2.807	0.06	24.00	1.01	8.53	0.46	67.45	731.89
WILLIAMS PRODUCTION-WEBSTER HILL COMP ST	06GA1279	-926.742	2.807	0.06	24.00	1.01	8.53	0.46	67.45	731.89
WILLIAMS PRODUCTION-WEBSTER HILL COMP ST	06GA1279	-926.742	2.807	0.02	20.34	0.33	7.32	0.31	27.40	735.22
WILLIAMS PRODUCTION-WEBSTER HILL COMP ST	06GA1279	-926.742	2.807	0.00	6.32	0.48	6.10	0.61	6.10	533.00
WILLIAMS PRODUCTION-RABBIT BRUSH	06GA1289	-940.676	-0.44	0.06	34.30	1.01	8.53	0.46	67.42	731.89
WILLIAMS PRODUCTION-RABBIT BRUSH	06GA1289	-940.676	-0.44	0.06	34.30	1.01	8.53	0.46	67.42	731.89
WILLIAMS PRODUCTION-RABBIT BRUSH	06GA1289	-940.676	-0.44	0.06	34.30	1.01	8.53	0.46	67.42	731.89
WILLIAMS PRODUCTION-RABBIT BRUSH	06GA1289	-940.676	-0.44	0.06	34.30	1.01	8.53	0.51	67.42	731.89
WILLIAMS PRODUCTION-RABBIT BRUSH	06GA1289	-940.676	-0.44	0.02	20.34	0.33	8.53	0.51	67.42	731.89
WILLIAMS PRODUCTION-RABBIT BRUSH	06GA1289	-940.676	-0.44	0.00	6.32	0.48	6.10	0.61	6.10	533.00
WILLIAMS PRODUCTION RMT-CRAWFORD TRAIL	06GA1073	-954.394	3.93	0.10	34.30	1.01	8.53	0.46	67.36	731.89
WILLIAMS PRODUCTION RMT-CRAWFORD TRAIL	06GA1073	-954.394	3.93	0.10	34.30	1.01	8.53	0.46	67.36	731.89
WILLIAMS PRODUCTION RMT-CRAWFORD TRAIL	06GA1073	-954.394	3.93	0.10	34.30	1.01	85.34	0.46	67.36	731.89
WILLIAMS PRODUCTION RMT-CRAWFORD TRAIL	06GA1073	-954.394	3.93	0.10	34.30	1.01	8.53	0.46	67.36	731.89
WILLIAMS PRODUCTION RMT-CRAWFORD TRAIL	06GA1073	-954.394	3.93	0.00	20.34	0.67	7.32	0.31	27.40	735.22
WILLIAMS PRODUCTION RMT-CRAWFORD TRAIL	06GA1073	-954.394	3.93	0.00	20.34	0.67	7.32	0.31	27.40	735.22
WILLIAMS PRODUCTION RMT-CRAWFORD TRAIL	06GA1073	-954.394	3.93	0.00	6.32	0.48	9.14	0.61	6.10	533.00
LARAMIE ENERGY - MEAD B PAD		-923.934	-1.067	0.00	0.20	0.00	6.10	0.61	3.05	644.11
LARAMIE ENERGY LLC - JONSSON PAD		-922.479	1.177	0.00	0.02	0.00	6.10	0.61	3.05	644.11
LARAMIE ENERGY LLC - JONSSON PAD		-905.948	-3.055	0.00	0.10	0.00	0.00	0.00	0.00	0.00
LARAMIE ENERGY LLC - JONSSON PAD		-907.655	-4.06	0.00	0.13	0.00	0.00	0.00	0.00	0.00
LARAMIE ENERGY LLC - JONSSON PAD		-911.052	-1.689	0.00	9.17	0.00	0.00	0.00	0.00	0.00
LARAMIE ENERGY LLC - JONSSON PAD		-944.491	-0.119	0.00	0.67	0.00	0.00	0.00	0.00	0.00

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
LARAMIE ENERGY LLC - JONSSON PAD		-908.101	-4.423	0.00	0.62	0.00	0.00	0.00	0.00	0.00
ANTERO - PICEANCE CORP. - DEVER A		-913.474	0.955	0.00	0.05	0.00	6.10	0.61	3.05	644.11
ANTERO - PICEANCE CORP. - GYPSUM RANCH A		-917.124	2.187	0.00	0.02	0.00	6.10	0.61	3.05	644.11
ANTERO - PICEANCE CORP. - GYPSUM RANCH A		-910.219	2.229	0.00	0.02	0.00	0.00	0.00	0.00	0.00
ANTERO - PICEANCE CORP. - ISLAND PARK B		-912.897	2.921	0.00	0.02	0.00	6.10	0.61	3.05	644.11
ANTERO - PICEANCE CORP. - NORTH BANK A		-914.98	3.563	0.00	0.02	0.00	6.10	0.61	3.05	644.11
ANTERO - PICEANCE CORP. - RIVER RANCH A		-912.549	2.887	0.00	0.02	0.00	6.10	0.61	3.05	644.11
ANTERO - PICEANCE CORP. - VALLEY FARMS B		-909.892	1.383	0.00	0.26	0.00	6.10	0.61	3.05	644.11
ANTERO- PICEANCE CORP. - VALLEY FARMS C		-909.532	1.34	0.00	0.27	0.00	6.10	0.61	3.05	644.11
ANTERO- PICEANCE CORP. - VALLEY FARMS C		-909.083	1.707	0.00	0.09	0.00	0.00	0.00	0.00	0.00
ANTERO - PICEANCE CORP. - SNYDER A		-915.501	2.408	0.00	0.04	0.00	6.10	0.61	3.05	644.11
ETC CANYON PIPELINE-BUZZARD CREEK	07GA0494	-910.331	2.064	0.00	0.00	0.06	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-BUZZARD CREEK	07GA0494	-910.331	2.064	0.00	0.00	4.72	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-BUZZARD CREEK	07GA0494	-903.824	-2.047	0.00	0.14	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-BUZZARD CREEK	07GA0494	-967.816	14.067	0.00	17.66	0.00	0.00	0.00	0.00	0.00
CHEVRON USA-PICEANCE BASIN 35-AV WELL PA	07GA0710	-967.859	13.673	0.03	17.70	0.42	7.01	0.51	19.20	743.56
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-804.736	39.581	0.00	0.00	4.71	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-785.52	47.862	0.00	0.00	2.46	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-793.596	46.638	0.00	0.00	2.90	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-809.551	59.458	0.00	0.00	4.23	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.13	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.03	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.15	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.03	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.10	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.02	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.14	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.57	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.57	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.57	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.48	0.00	0.00	0.00	0.00
FLINTSTONE GRAVEL & TRUCKING - FLINTSTON	06GR0679	-777.475	40.773	0.00	0.00	0.25	0.00	0.00	0.00	0.00
UNITED COMPANIES - GUNNISION REDI-MIX PI		-860.921	-111.356	0.00	0.00	0.30	0.00	0.51	30.08	294.11
UNITED COMPANIES - GUNNISION REDI-MIX PI	02GU0753	-860.921	-111.356	0.00	0.00	0.02	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	22.96	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	0.41	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	0.15	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	0.01	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	0.88	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	0.44	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	1.79	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	0.16	0.00	0.51	30.08	294.11
OXBOW MINING INC	98GU0812	-900.847	-65.927	0.00	0.00	0.41	0.00	0.51	30.08	294.11
MOUNT EMMONS MINING CO (WAS CLIMAX)	12GU988-3	-863.903	-77.271	0.00	0.00	0.22	12.50	0.27	30.08	294.11
MOUNT EMMONS MINING CO (WAS CLIMAX)	12GU988-3	-863.903	-77.271	0.00	0.00	0.05	12.50	0.27	30.08	294.11
MOUNTAIN COAL CO. LLC (WEST ELK MINE)	99GU0832	-898.953	-67.072	0.00	0.00	42.10	0.00	0.51	30.08	294.11
GUNNISON COUNTY LANDFILL (PUBLIC WORKS)	83GU236F	-833.364	-126.38	0.00	0.00	3.35	0.00	0.51	30.08	294.11
VARRA COMPANIES - PIT 118	99GU0787F	-853.366	-114.738	0.00	0.00	7.88	0.00	0.51	30.08	294.11
VARRA COMPANIES - PIT 118	99GU0787F	-853.366	-114.738	0.00	0.00	0.13	0.00	0.51	30.08	294.11
VARRA COMPANIES - PIT 118	99GU0788	-853.366	-114.738	0.00	0.00	0.83	0.00	0.51	30.08	294.11
VARRA COMPANIES - PIT 118	99GU0788	-853.366	-114.738	0.00	0.00	0.97	0.00	0.51	30.08	294.11
VARRA COMPANIES - PIT 118	99GU0789	-853.366	-114.738	0.00	0.00	0.06	0.00	0.51	30.08	294.11
VARRA COMPANIES - PIT 118	99GU0789	-853.366	-114.738	0.00	0.00	0.04	0.00	0.51	30.08	294.11
RAGGED MOUNTAIN C.S.	04GU0118	-898.636	-40.983	0.00	12.20	0.00	7.62	0.36	27.10	699.67
RAGGED MOUNTAIN C.S.	04GU0118	-898.636	-40.983	0.00	0.21	0.00	0.00	0.00	0.00	0.00
RAGGED MOUNTAIN C.S.	05GU0789	-898.636	-40.983	0.00	0.21	0.01	0.00	0.51	30.08	295.22
SG INTERESTS I LTD - FEDERAL 24-1	06GU0957	-892.527	-49.83	0.01	22.50	0.11	3.05	0.10	138.44	997.44
PUBLIC SERVICE CO CAMEO PLT	11ME311	-970.529	-33.458	42.80	-63.10	-23.00	45.72	2.67	7.77	399.67
PUBLIC SERVICE CO CAMEO PLT	93ME975-2	-970.529	-33.458	0.00	0.00	0.50	0.00	0.51	30.08	294.11
QUIKRETE GRAND JUNCTION	93ME1379	-994.731	-37.575	0.00	0.00	20.61	13.72	1.46	21.49	294.11
QUIKRETE GRAND JUNCTION	93ME1379	-994.731	-37.575	0.00	0.00	0.35	13.72	1.46	21.49	294.11
QUIKRETE GRAND JUNCTION	93ME1379	-994.731	-37.575	0.00	0.00	0.00	15.24	0.91	22.65	288.56
QUIKRETE GRAND JUNCTION	93ME1379	-994.731	-37.575	0.00	0.00	0.03	4.88	0.61	4.85	310.78
COORSTEK - GRAND JUNCTION OPERATIONS	95ME981	-995.269	-37.444	0.00	47.80	0.00	0.00	0.51	30.08	294.11
COORSTEK - GRAND JUNCTION OPERATIONS	95ME981	-995.269	-37.444	0.00	0.00	0.30	0.00	0.51	30.08	294.11
COORSTEK - GRAND JUNCTION OPERATIONS	95ME981	-995.269	-37.444	0.00	0.90	0.00	0.00	0.51	30.08	294.11
COORSTEK - GRAND JUNCTION OPERATIONS	95ME981	-995.269	-37.444	0.00	0.00	0.02	0.00	0.51	30.08	294.11
COORSTEK - GRAND JUNCTION OPERATIONS	95ME981	-995.269	-37.444	0.00	0.00	6.21	0.00	0.51	30.08	294.11
COORSTEK - GRAND JUNCTION OPERATIONS	95ME981	-995.269	-37.444	0.00	0.00	0.00	0.00	0.51	30.08	294.11
WHITEWATER BUILDING MATERIALS	95ME589	-992.078	-40.76	0.00	0.00	1.06	19.81	0.61	2.23	294.11
GRAND JUNCTION CONCRETE PIPE / READY MIX	95ME516	-988.56	-36.045	0.00	0.00	0.31	0.00	0.51	30.08	294.11
GRAND JUNCTION CONCRETE PIPE / READY MIX	95ME516	-988.56	-36.045	0.00	0.00	0.18	0.00	0.51	30.08	294.11
ETC CANYON PIPELINE - BAR X C.S.	08ME0021	-1026.806	-13.996	0.01	3.90	0.20	3.66	0.51	24.57	699.67
COLORADO STATE UNIVERSITY CSU	03ME0664	-988.504	-40.393	0.34	0.56	0.47	9.14	0.46	30.08	1255.22
GRAND JUNCTION PIPE & SUPPLY CO	82ME180F	-1005.886	-30.291	0.00	0.00	8.96	0.00	0.51	30.08	298.00
LAFARGE WEST INC. - LATHAM BURKETT PIT	83ME073F	-958.696	-15.411	0.00	0.00	0.40	0.00	0.51	30.08	298.00
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	02ME0127F	-983.036	-44.872	0.00	0.00	0.15	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	02ME0127F	-983.036	-44.872	0.00	0.00	1.28	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	02ME0127F	-983.036	-44.872	0.00	0.00	9.20	0.00	0.00	0.00	0.00
SNOWCAP COAL COMPANY NC - CAMEO MINE	11ME670-1F	-970.642	-32.776	0.00	0.00	0.01	0.00	0.51	30.08	294.11
SNOWCAP COAL COMPANY NC - CAMEO MINE	13ME073F	-970.642	-32.776	0.00	0.00	6.89	0.00	0.51	30.08	294.11
COLORADO FUEL MANUFACTURERS	96ME349	-996.432	-32.997	0.00	5.74	0.00	0.00	0.51	30.08	294.11
COLORADO FUEL MANUFACTURERS	96ME349	-996.432	-32.997	0.00	0.00	0.44	0.00	0.51	30.08	294.11
COLORADO FUEL MANUFACTURERS	96ME349	-996.432	-32.997	0.00	0.65	0.00	0.00	0.51	30.08	294.11
COLORADO FUEL MANUFACTURERS	96ME349	-996.432	-32.997	0.00	21.30	0.00	1.83	0.06	30.08	785.78
COLORADO FUEL MANUFACTURERS	96ME349	-996.432	-32.997	0.00	0.00	1.49	1.83	0.06	30.08	785.78
COLORADO FUEL MANUFACTURERS	96ME349	-996.432	-32.997	1.39	0.00	0.00	1.83	0.06	30.08	785.78
ROICE-HURST HUMANE SOCIETY	87ME021I	-981.937	-40.813	0.14	0.05	0.02	7.62	0.37	30.08	676.33
GRAND JUNCTION MESA CO PERSIGO WWTP	88ME033	-998.18	-34.968	0.01	0.30	0.01	5.18	0.27	4.82	417.44
GRAND JUNCTION MESA CO PERSIGO WWTP	88ME033	-998.18	-34.968	0.01	0.30	0.01	2.13	0.27	3.51	417.44
ELAM CONST INC SNOOKS GRVL MINE	88ME054F	-1006.743	-29.283	0.00	0.00	0.22	0.00	0.51	30.08	294.11
ELAM CONST INC SNOOKS GRVL MINE	88ME054F	-1006.743	-29.283	0.00	0.00	0.26	0.00	0.51	30.08	294.11
SOURCEGAS DBA ROCKY MT - COLLBRAN	02ME0757	-939.291	-26.566	0.01	3.57	0.05	3.96	0.20	24.20	633.80
MINOVA USA INC.	03ME0432	-997.401	-35.47	0.00	0.00	0.26	3.05	0.21	14.72	294.11
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	96ME783	-997.658	-35.406	0.00	0.00	0.06	3.05	0.18	30.08	259.67
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	06ME0556	-997.658	-35.406	0.00	0.00	3.63	9.14	0.96	28.44	388.56
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	06ME0556	-997.658	-35.406	0.00	0.00	4.43	9.14	0.96	28.44	388.56
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	06ME0556	-997.658	-35.406	14.00	17.30	0.00	9.14	0.96	28.44	388.56
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.00	3.97	0.00	4.88	0.41	30.08	477.44

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.00	0.00	0.40	4.88	0.41	30.08	477.44
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	14.29	0.00	0.00	4.88	0.41	30.08	477.44
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.00	0.12	0.00	0.00	0.51	30.08	294.11
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.00	0.00	0.05	0.00	0.00	0.00	0.00
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.00	0.00	0.06	0.00	0.51	30.08	294.11
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.01	0.00	0.00	0.00	0.00	0.00	0.00
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.01	0.00	0.00	0.00	0.51	30.08	294.11
KC ASPHALT LLC -GRAND JUNCTION FACILITY	02ME0206	-993.252	-40.535	0.00	0.38	0.03	4.88	0.41	30.08	477.44
COLORADO FUEL MANUFACTURERS	94ME548	-1002.206	-31.372	0.00	26.80	0.00	9.14	0.36	30.08	294.11
COLORADO FUEL MANUFACTURERS	94ME548	-1002.206	-31.372	0.00	0.00	0.01	9.14	0.36	30.08	294.11
COLORADO FUEL MANUFACTURERS	94ME548	-1002.206	-31.372	0.81	0.00	0.00	9.14	0.36	30.08	294.11
PARKERSON CONSTRUCTION INC	94ME533F	-950.117	-31.868	0.00	0.00	3.32	0.00	0.51	30.08	294.11
PARKERSON CONSTRUCTION INC	94ME533F	-950.117	-31.868	0.00	0.00	0.04	0.00	0.51	30.08	294.11
PLAINS EXPLORATION- BRUSH CREEK PROCESSI	06ME0359	-927.343	-22.878	0.00	17.90	0.00	0.00	0.00	0.00	0.00
PLAINS EXPLORATION- BRUSH CREEK PROCESSI	06ME0360	-927.343	-22.878	0.00	5.10	0.00	0.00	0.00	0.00	0.00
PLAINS EXPLORATION- BRUSH CREEK PROCESSI	06ME0360	-927.343	-22.878	0.00	5.10	0.00	0.00	0.00	0.00	0.00
SUNCOR ENERGY (U.S.A.)	96ME354	-998.388	-35.198	0.00	1.10	0.00	0.00	0.51	30.08	294.11
MOORES MINING RANCHING & SAWMILL	96ME806F	-1032.825	-77.682	0.00	0.00	25.00	0.00	0.51	30.08	294.11
ETC CANYON PIPELINE -PREMIER DEBEQUE	01ME0792	-961.651	-14.351	0.00	24.30	0.06	3.66	0.15	13.17	844.11
ETC CANYON PIPELINE -PREMIER DEBEQUE	01ME0792	-961.651	-14.351	0.00	33.10	0.00	0.00	0.00	0.00	0.00
MAACO AUTO PAINTING - FGTS INC.	98ME0111	-988.009	-39.212	0.00	0.00	0.18	0.00	0.51	30.08	294.11
PARKERSON CONST INC	97ME0365F	-985.249	-45.939	0.00	0.00	12.35	0.00	0.00	0.00	0.00
PARKERSON CONST INC	97ME0365F	-985.249	-45.939	0.00	0.00	2.10	0.00	0.00	0.00	0.00
FIVE LIGHTS PET CREMATORY	98ME0176	-999.108	-29.175	0.13	0.04	0.00	7.62	0.46	5.82	702.44
FINAL PAWS	99ME0174	-996.975	-33.243	0.00	0.00	0.05	5.49	0.31	10.15	783.00
CALLAHAN EDFAST MORTUARY/CREMATORY	02ME0632	-994.332	-36.81	0.02	0.10	0.02	6.10	0.55	30.08	1184.11
M A CONCRETE	00ME0134F	-997.485	-35.161	0.00	0.00	0.03	0.00	0.51	30.08	294.11
PUBLIC SERVICE CO. OF CO. - ORCHARD MESA	01ME0175	-980.853	-43.341	-0.05	20.40	0.01	7.62	0.25	12.62	790.78
SLATE RIVER RESOURCES - BADGER WGP	01ME0305	-1018.226	-7.093	0.02	15.09	0.33	3.05	0.31	12.89	633.80
SLATE RIVER RESOURCES - BADGER WGP	01ME0308	-1018.226	-7.093	0.21	25.30	2.65	0.00	0.51	30.08	294.11
SLATE RIVER RESOURCES - BADGER WGP	01ME0340	-1018.226	-7.093	0.02	15.09	0.33	3.05	0.31	12.89	633.80
SLATE RIVER RESOURCES - BADGER WGP	04ME1340	-1018.226	-7.093	0.03	14.70	0.53	0.61	0.31	38.95	866.33
ENCANA - PLATEAU CREEK	02ME0012	-953.232	-33.346	0.54	0.00	6.80	0.00	0.51	30.08	299.67
ENCANA - PLATEAU CREEK	02ME0012	-983.806	-41.391	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ENCANA - PLATEAU CREEK	02ME0012	-983.806	-41.391	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HALLIBURTON ENERGY SERVICES	03ME0602	-983.806	-41.391	0.00	0.00	0.00	7.32	0.56	0.82	294.11
HALLIBURTON ENERGY SERVICES	03ME0602	-983.806	-41.391	0.00	0.00	0.01	7.32	0.56	0.82	294.11
HALLIBURTON ENERGY SERVICES	03ME0602	-983.806	-41.391	0.00	0.00	0.02	7.32	0.56	0.82	294.11
HALLIBURTON ENERGY SERVICES		-983.806	-41.391	0.00	0.00	0.00	11.58	0.66	0.40	294.11
HALLIBURTON ENERGY SERVICES		-983.806	-41.391	0.00	0.00	0.00	11.58	0.66	0.40	294.11
HALLIBURTON ENERGY SERVICES		-983.806	-41.391	0.00	0.00	0.00	11.58	0.66	0.40	294.11
ENCANA WEST - BUZZARD CREEK	06ME0940	-922.489	-25.113	0.01	25.80	0.15	0.00	0.51	30.08	294.11
EPHEMERAL RESOURCES	02ME0652F	-988.298	-41.037	0.00	0.00	0.12	0.00	0.51	30.08	294.11
EPHEMERAL RESOURCES	02ME0652F	-988.298	-41.037	0.00	0.00	7.86	0.00	0.51	30.08	294.11
ELAM CONSTRUCTION INC - DEBEQUE GRAVEL	02ME0766F	-960.567	-19.291	0.00	0.00	3.05	0.00	0.51	30.08	294.11
SCHLUMBERGER TECHNOLOGY CORPORATION	02ME0936	-998.813	-32.713	0.00	0.00	0.11	6.10	0.40	9.42	294.11
SCHLUMBERGER TECHNOLOGY CORPORATION	02ME0936	-998.813	-32.713	0.00	0.00	0.25	6.10	0.40	9.42	294.11
OLDCASTLE SW GROUP DBA UNITED COMPANIES	02ME0988F	-1009.836	-26.237	0.00	0.00	6.00	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP DBA UNITED COMPANIES	02ME0988F	-1009.836	-26.237	0.00	0.00	30.80	0.00	0.51	30.08	294.11
HALLIBURTON ENERGY SVCS	03ME0351	-983.546	-39.101	0.00	0.00	0.00	7.32	0.56	0.58	294.11
HALLIBURTON ENERGY SVCS	03ME0351	-983.546	-39.101	0.00	0.00	0.01	7.32	0.56	0.58	294.11
HALLIBURTON ENERGY SVCS	03ME0351	-983.546	-39.101	0.00	0.00	0.20	8.53	0.56	0.58	294.11
PARKERSON CONSTRUCTION INC - 2 ROAD PIT	03ME0760F	-1033.659	-47.413	0.00	0.00	0.01	0.00	0.51	30.08	294.11
PARKERSON CONSTRUCTION INC - 2 ROAD PIT	03ME0760F	-1033.659	-47.413	0.00	0.00	32.89	0.00	0.51	30.08	294.11
TRANSCOLORADO GAS TR CO - WHITEWATER CS	03ME1030	-979.164	-49.196	0.05	29.83	0.88	7.62	0.46	96.68	633.80
TRANSCOLORADO GAS TR CO - WHITEWATER CS	03ME1031	-979.164	-49.196	0.00	3.28	0.06	7.62	0.25	23.10	633.80
TRANSCOLORADO GAS TR CO - WHITEWATER CS	03ME1032	-979.164	-49.196	0.00	1.35	0.04	7.62	0.25	23.10	633.80
M.A. CONCRETE CONST - COLE GRAVEL PIT	04ME1133F	-977.02	-57.921	0.00	0.00	0.03	0.00	0.51	30.08	294.11
M.A. CONCRETE CONST - COLE GRAVEL PIT	04ME1133F	-977.02	-57.921	0.00	0.00	9.56	0.00	0.51	30.08	294.11
NATCO GROUP INC.	04ME1273	-999.199	-34.368	0.00	0.00	4.10	0.00	0.51	30.08	294.11
GRAND JUNCTION CONCRETE PIPE-BATCH PLT	05ME0736	-997.362	-35.666	0.00	0.00	1.32	0.00	0.51	30.08	294.11
GRAND JUNCTION CONCRETE PIPE-BATCH PLT	05ME0736	-997.362	-35.666	0.00	0.00	1.57	0.00	0.51	30.08	294.11
M. A. CONCRETE - 20 ROAD GRAVEL PIT	05ME0943F	-1001.734	-32.009	0.00	0.00	0.20	0.00	0.51	30.08	294.11
M. A. CONCRETE - 20 ROAD GRAVEL PIT	05ME0943F	-1001.734	-32.009	0.00	0.00	5.59	0.00	0.51	30.08	294.11
PLAINS EXPLORATION - EAST PLATEAU C.S.	06ME0217	-935.075	-32.055	0.03	19.40	0.44	0.31	0.61	30.08	727.44
PLAINS EXPLORATION - EAST PLATEAU C.S.	06ME0354	-935.075	-32.055	0.03	19.40	0.44	0.31	0.61	30.08	729.67
PLAINS EXPLORATION - EAST PLATEAU C.S.	06ME0355	-935.075	-32.055	0.03	19.40	0.44	0.31	0.61	30.08	727.44
PLAINS EXPLORATION - EAST PLATEAU C.S.	07ME0460	-935.075	-32.055	0.03	19.40	0.44	0.00	0.51	30.08	4999.67
DELTA PETROLEUM CORPORATION - VEGA STA.	06ME0407	-919.413	-25.579	0.00	9.71	0.60	80.77	0.36	30.08	908.00
DELTA PETROLEUM CORPORATION - VEGA STA.	07ME0388	-919.413	-25.579	0.03	8.11	0.57	7.62	0.35	38.10	810.78
HALLIBURTON ENERGY - CAMEO RAIL SPUR	06ME0728	-969.797	-32.89	0.00	0.00	0.62	0.00	0.51	30.08	294.11
HALLIBURTON ENERGY - CAMEO RAIL SPUR	06ME0728	-969.797	-32.89	0.00	0.00	9.82	0.00	0.51	30.08	294.11
HALLIBURTON ENERGY - CAMEO RAIL SPUR	06ME0729	-969.797	-32.89	0.30	4.53	0.32	0.00	0.51	30.08	294.11
HALLIBURTON ENERGY - CAMEO RAIL SPUR	06ME0729	-928.605	-23.021	0.00	30.40	0.00	0.00	0.00	0.00	0.00
HALLIBURTON ENERGY - CAMEO RAIL SPUR	06ME0729	-935.582	-31.39	0.00	30.40	0.00	0.00	0.00	0.00	0.00
HALLIBURTON ENERGY - CAMEO RAIL SPUR	06ME0729	-1007.857	-26.78	0.00	0.00	0.05	0.00	0.00	0.00	0.00
HALLIBURTON ENERGY SVCS - BARITE STORAGE	06ME1330	-1007.857	-26.78	0.72	3.10	0.77	1.83	0.10	10.91	810.78
HALLIBURTON ENERGY SVCS - BARITE STORAGE	06ME1330	-1007.688	-26.435	0.00	0.00	0.83	0.00	0.00	0.00	0.00
ASPEN OPERATING LLC - KANNAH CREEK	07ME0434	-976.514	-55.36	0.03	19.40	0.46	6.10	0.31	62.21	729.67
PLAINS EXPLORATION- ALKALI CREEK C.S.	07ME0498	-910.466	-17.858	0.03	19.40	0.44	0.00	0.51	30.08	729.67
PLAINS EXPLORATION- ALKALI CREEK C.S.	07ME0833	-910.466	-17.858	0.03	19.40	0.44	0.00	0.51	30.08	4999.67
PLAINS EXPLORATION- ALKALI CREEK C.S.	07ME0834	-910.466	-17.858	0.03	19.40	0.44	0.00	0.51	30.08	729.67
PLAINS EXPLORATION- ALKALI CREEK C.S.	07ME0835	-910.466	-17.858	0.03	19.40	0.44	0.00	0.51	30.08	729.67
PLAINS EXPLORATION- ALKALI CREEK C.S.	07ME0835	-910.466	-17.858	0.00	3.70	0.00	0.00	0.00	0.00	0.00
NAVAJO DEVELOPMENT LLC - CREEDE AIRPORT	04MI0202	-872.046	-193.866	0.00	0.00	0.97	0.00	0.51	30.08	294.11
TRAPPER MINING INC	11MF253-1	-892.273	99.148	0.00	0.00	2.15	0.00	0.51	30.08	294.11
TRAPPER MINING INC	11MF253-1	-892.273	99.148	0.00	0.00	0.03	0.00	0.51	30.08	294.11
TRAPPER MINING INC	11MF253-1	-892.273	99.148	0.00	0.00	17.48	0.00	0.51	30.08	294.11
TRAPPER MINING INC	11MF253-1	-892.273	99.148	0.00	0.00	5.81	0.00	0.51	30.08	294.11
TRAPPER MINING INC	11MF253-1	-892.273	99.148	0.00	0.00	67.26	0.00	0.51	30.08	294.11
TRAPPER MINING INC	11MF253-1	-892.273	99.148	0.00	0.00	1.86	0.00	0.51	30.08	294.11
TRAPPER MINING INC	11MF253-1	-892.273	99.148	0.00	0.00	98.48	0.00	0.51	30.08	294.11
BTU EMPIRE CORP - CRAIG AREA MINE	83MF403-4	-893.18	104.703	0.00	0.00	0.19	0.00	0.00	0.00	0.00
BTU EMPIRE CORP - CRAIG AREA MINE	83MF403-4	-893.18	104.703	0.00	0.00	0.19	0.00	0.00	0.00	0.00
BTU EMPIRE CORP - CRAIG AREA MINE	93MF970F	-893.18	104.703	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BTU EMPIRE CORP - CRAIG AREA MINE	93MF970F	-893.18	104.703	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BTU EMPIRE CORP - CRAIG AREA MINE	93MF970F	-893.18	104.703	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRI STATE GENERATION CRAIG	12MF322-1	-891.619	103.128	228.90	758.40	0.40	182.88	7.62	22.16	344.11
TRI STATE GENERATION CRAIG	11MF332	-891.619	103.128	0.00	0.00	0.00	37.49	0.69	19.02	449.67

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
TRI STATE GENERATION CRAIG	11MF332	-891.619	103.128	0.00	0.00	0.00	37.49	0.69	19.02	449.67
TRI STATE GENERATION CRAIG	11MF415	-891.619	103.128	0.00	0.00	3.00	6.10	1.55	9.45	294.11
TRI STATE GENERATION CRAIG	12MF322-2	-891.619	103.128	0.00	0.00	0.03	0.00	0.51	30.08	294.11
TRI STATE GENERATION CRAIG	12MF322-2	-891.619	103.128	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TRI STATE GENERATION CRAIG	11MF994F	-891.619	103.128	0.00	0.00	0.10	0.00	0.51	30.08	294.11
TRI STATE GENERATION CRAIG	11MF994F	-891.619	103.128	0.00	0.00	0.17	0.00	0.51	30.08	294.11
TRI STATE GENERATION CRAIG	12MF322-3	-891.619	103.128	0.00	0.00	13.10	0.00	0.51	30.08	294.11
TRI STATE GENERATION CRAIG	12MF322-4	-891.619	103.128	0.00	0.00	0.00	0.00	0.51	30.08	294.11
QUESTAR PIPELINE COMPANY		-945.4	164.009	0.00	5.38	0.00	9.75	0.24	14.91	824.67
QUESTAR PIPELINE COMPANY		-945.4	164.009	0.01	99.40	0.19	10.97	0.20	49.50	824.67
QUESTAR PIPELINE COMPANY		-945.4	164.009	0.00	42.20	0.00	10.97	0.20	49.50	824.67
QUESTAR PIPELINE COMPANY	90MF242	-945.4	164.009	0.00	4.45	0.00	5.18	0.31	63.76	721.33
QUESTAR PIPELINE COMPANY	94MF252-1	-945.4	164.009	0.00	0.03	0.00	3.96	0.21	24.20	633.80
QUESTAR PIPELINE COMPANY	94MF252-2	-945.4	164.009	0.00	0.00	0.00	3.96	0.21	24.20	633.80
QUESTAR PIPELINE COMPANY	05MF0534	-945.4	164.009	0.00	13.30	0.00	6.10	0.61	30.08	866.33
WEXPRO CO HIAWATHA OIL FIELD	06MF0844	-968.857	170.795	0.01	2.70	0.20	4.57	0.15	30.08	894.11
QUESTAR GAS MGMT CO W HIAWATHA COMP STA	05MF0723	-975.413	171.438	0.02	19.40	0.41	6.10	0.61	30.08	866.33
QUESTAR PIPELINE CO STATE LINE COMP STA	95MF955-1	-924.574	165.27	0.00	0.67	0.01	4.57	0.46	73.82	727.44
QUESTAR PIPELINE CO STATE LINE COMP STA	95MF955-1	-924.574	165.27	0.00	0.00	0.00	4.57	0.46	73.82	727.44
QUESTAR GAS MANAGEMENT - E HIAWATHA C.S.	96MF715-5 (G	-969.673	172.395	0.00	12.40	0.03	3.35	0.09	26.91	671.89
QUESTAR GAS MANAGEMENT - E HIAWATHA C.S.	04MF0936	-969.673	172.395	0.02	8.20	0.30	4.57	0.31	3.54	735.78
QUESTAR GAS MANAGEMENT - E HIAWATHA C.S.	05MF0429	-969.673	172.395	0.00	0.16	0.01	6.10	0.31	30.08	421.89
WEXPRO CO ACE UNIT 8 WELLSITE	93MF1132	-942.866	164.867	0.00	15.94	0.08	1.52	0.15	123.44	866.33
LAFARGE WEST INC. - BUNN RANCH PIT	97MF0469F	-885.484	107.388	0.00	0.00	2.81	0.00	0.51	30.08	294.11
LAFARGE WEST INC. - BUNN RANCH PIT	97MF0469F	-885.484	107.388	0.00	0.00	0.02	0.00	0.51	30.08	294.11
CUSTOM ENERGY CONSTRUCTION INC BUCK PEAK	94MF782	-883.531	104.819	0.00	1.50	0.00	0.00	0.00	0.00	0.00
MERRION OIL & GAS - BLUE GRAVEL	97MF0647	-886.605	131.572	0.00	9.40	0.00	2.74	0.14	25.21	896.89
MERRION OIL & GAS - BLUE GRAVEL	03MF0089	-886.605	131.572	0.00	3.23	0.02	0.00	0.51	30.08	294.11
MERRION OIL & GAS - BLUE GRAVEL	03MF0113	-886.605	131.572	0.01	6.78	0.07	0.00	0.51	30.08	294.11
WESTERN GAS RESOURCES INC SAND WASH STA	97MF0649	-913.645	150.829	0.02	15.90	0.16	7.62	0.44	4.27	541.33
TRUE OIL LLC - BTA FEDERAL #12-33	00MF0096	-887.091	156.925	0.00	8.50	0.00	0.00	0.51	30.08	294.11
QUESTAR GAS MANAGEMENT CO. - LION C.S.	03MF0662	-967.675	167.404	0.03	14.30	0.48	4.57	0.31	30.08	866.33
NORTHERN LIGHTS PET CREMATORY	02MF0174	-879.9	116.584	0.08	0.58	0.10	4.88	0.37	6.61	810.78
MOFFAT LIMESTONE INC - JUNIPER MT. GRAVE	03MF0462F	-930.705	111.149	0.00	0.00	0.02	0.00	0.51	30.08	294.11
MOFFAT LIMESTONE INC - JUNIPER MT. GRAVE	03MF0462F	-930.705	111.149	0.00	0.00	2.42	0.00	0.51	30.08	294.11
CHEVRON USA INC. - VAN SCHAICK A-8		-975.187	171.618	0.00	2.90	0.02	1.83	0.51	32.16	949.67
CEDAR RIDGE LLC - BROWNLEE 24-1	04MF0465	-862.336	157.918	0.00	10.72	0.06	0.00	0.51	30.08	294.11
NEW FRONTIER ENERGY- CF&I CORP. #1	04MF0468	-863.082	158.41	0.01	12.20	0.21	0.00	0.51	30.08	294.11
CEDAR RIDGE LLC - ROBIDOUX 13-12-89 #1	04MF0470	-863.085	158.41	0.00	10.73	0.06	0.00	0.51	30.08	294.11
CEDAR RIDGE LLC - ROBIDOUX 23-13 CBM #1	04MF0471	-862.993	158.692	0.01	17.20	0.09	0.00	0.51	30.08	294.11
CEDAR RIDGE LLC - ROBIDOUX 23-13 CBM #1	04MF0472	-862.993	158.692	0.00	10.72	0.06	0.00	0.51	30.08	294.11
PLAINS MARKETING LP - BUCK PEAK STATION	04GA0104	-889.362	104.951	0.00	0.00	4.95	0.00	0.51	30.08	294.11
WESTERN GAS RESOURCES - FEDERAL 1-14-28	07MF0019	-908.709	141.782	0.00	1.98	0.07	3.35	0.10	3.81	813.00
J-W OPERATING CO- BIG HOLE FEDERAL	06MF0798	-916.085	147.489	0.00	8.74	0.00	1.83	0.05	95.40	991.33
J-W OPERATING CO- BIG HOLE FEDERAL	06MF0798	-878.913	120.44	0.00	6.52	0.00	0.00	0.00	0.00	0.00
QUESTAR EXPLORATION-SPARKS RIDGE UNIT 1	07MF1055	-984.434	167.381	0.00	10.36	0.03	2.44	0.15	30.08	633.80
QUESTAR EXPLORATION-SPARKS RIDGE UNIT 1	07MF1055	-943.173	162.525	0.00	0.30	0.00	0.00	0.00	0.00	0.00
QUESTAR E&P Cutthroat Battery A	87MN241-1	-1046.887	-210.357	0.00	25.20	0.00	3.35	0.15	26.76	751.89
QUESTAR E&P Cutthroat Battery A	87MN241-1	-1046.887	-210.357	0.00	0.00	0.03	3.35	0.15	26.76	751.89
QUESTAR E&P Cutthroat Battery A	87MN241-1	-1046.887	-210.357	0.01	0.00	0.00	3.35	0.15	26.76	751.89
QUESTAR E&P Cutthroat Battery A	87MN241-2	-1046.887	-210.357	0.00	1.37	0.00	2.44	0.09	30.08	872.44
QUESTAR E&P Cutthroat Battery A	87MN241-2	-1046.887	-210.357	0.00	0.00	0.02	2.44	0.09	30.08	872.44
QUESTAR E&P Cutthroat Battery A	87MN241-2	-1046.887	-210.357	0.00	0.00	0.00	2.44	0.09	30.08	872.44
QUESTAR E&P Cutthroat Battery A	87MN241-3	-1046.887	-210.357	0.00	17.80	0.00	1.83	0.12	30.08	910.78
QUESTAR E&P Cutthroat Battery A	87MN241-3	-1046.887	-210.357	0.00	8.42	0.00	5.79	0.31	4.66	807.44
QUESTAR E&P Cutthroat Battery A	87MN241-3	-1046.887	-210.357	0.00	0.00	0.03	1.83	0.12	30.08	910.78
QUESTAR E&P Cutthroat Battery A	87MN241-3	-1046.887	-210.357	0.00	0.00	0.03	5.79	0.31	4.66	807.44
QUESTAR E&P Cutthroat Battery A	87MN241-3	-1046.887	-210.357	0.01	0.00	0.00	1.83	0.12	30.08	910.78
QUESTAR E&P Cutthroat Battery A	87MN241-3	-1046.887	-210.357	0.01	0.00	0.00	5.79	0.31	4.66	807.44
QUESTAR E&P Cutthroat Battery B	87MN240-1	-1045.766	-214.404	0.00	18.68	0.00	3.35	0.15	26.76	751.89
QUESTAR E&P Cutthroat Battery B	87MN240-1	-1045.766	-214.404	0.00	0.00	0.07	3.35	0.15	26.76	751.89
QUESTAR E&P Cutthroat Battery B	87MN240-1	-1045.766	-214.404	0.00	0.00	0.00	3.35	0.15	26.76	751.89
QUESTAR E&P Cutthroat Battery B	87MN240-2	-1045.766	-214.404	0.00	8.50	0.00	2.44	0.10	43.74	872.44
QUESTAR E&P Cutthroat Battery B	87MN240-2	-1045.766	-214.404	0.00	0.00	0.05	2.44	0.10	43.74	872.44
QUESTAR E&P Cutthroat Battery B	87MN240-2	-1045.766	-214.404	0.00	0.00	0.00	2.44	0.10	43.74	872.44
MID-AMERICA PIPELINE CO DOLORES STA	06MN1225	-1004.473	-222.019	0.01	28.22	0.46	8.53	0.61	52.58	767.44
NORTHWEST PIPELINE CORP PLEASANT VIEW	91MN343-1	-1026.931	-201.741	0.12	-8.17	-0.13	15.85	1.22	31.30	802.44
NORTHWEST PIPELINE CORP PLEASANT VIEW	91MN343-2	-1026.931	-201.741	0.50	-8.17	-0.13	15.85	1.22	31.30	802.44
QUESTAR E & P- ISLAND BUTTE - B	98MN0178	-1047.427	-202.404	0.00	52.13	0.00	5.79	0.31	4.63	633.80
MC STONE AGGREGATES-HAY CAMP PIT	95MN763F	-1005.342	-216.861	0.00	0.00	0.03	0.00	0.51	30.08	294.11
MC STONE AGGREGATES-HAY CAMP PIT	95MN763F	-1005.342	-216.861	0.00	0.00	2.60	0.00	0.51	30.08	294.11
MUSCANELL MILLWORKS	02MN0146	-1024.528	-213.297	0.00	7.10	8.80	9.75	6.43	5.36	449.67
QUESTAR EXPLORATION - CUTTHROAT #5	02MN1019	-1045.77	-214.397	0.00	14.20	0.00	2.13	0.76	38.13	877.44
QUESTAR EXPLORATION - CUTTHROAT #8	04MN0597	-1045.881	-215.2	0.00	2.61	0.01	0.00	0.51	30.08	294.11
SKY UTE SAND & GRAVEL	05MN0403	-1018.85	-225.898	0.00	0.00	0.26	0.00	0.51	30.08	294.11
SKY UTE SAND & GRAVEL	05MN0403	-1018.85	-225.898	0.00	0.00	0.84	0.00	0.51	30.08	294.11
ROBERT L. BAYLESS - NORTH MAIL TAIL #1	06MN0437	-1018.306	-208.966	0.00	5.22	0.00	0.00	0.00	0.00	0.00
ROBERT L. BAYLESS - NORTH MAIL TAIL #1	06MN0437	-1015.615	-225.601	0.00	0.00	0.29	0.00	0.00	0.00	0.00
ROBERT L. BAYLESS - NORTH MAIL TAIL #1	06MN0437	-1015.615	-225.601	0.00	0.00	0.96	0.00	0.00	0.00	0.00
TRI STATE GENERATION NUCLA	84MO120-1	-999.365	-131.17	-190.80	625.00	-12.00	65.53	3.66	23.35	397.44
TRI STATE GENERATION NUCLA	98MO0484	-999.365	-131.17	0.00	0.00	0.10	0.00	0.51	30.08	294.11
TRI STATE GENERATION NUCLA	96MO382	-999.365	-131.17	0.00	0.00	0.23	0.00	0.51	30.08	294.11
TRI STATE GENERATION NUCLA	96MO382	-999.365	-131.17	0.00	0.00	0.06	0.00	0.51	30.08	294.11
TRI STATE GENERATION NUCLA	96MO703	-999.365	-131.17	0.00	0.00	1.60	8.53	8.53	9.66	310.78
WESTERN FUELS CO LLC NEW HORIZON MINE	88MO234F	-1002.575	-127.626	0.00	0.00	54.67	0.00	0.51	30.08	294.11
WESTERN FUELS CO LLC NEW HORIZON MINE	88MO234F	-1002.575	-127.626	0.00	14.80	0.00	0.00	0.51	30.08	294.11
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.05	0.00	0.51	30.08	294.11
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.16	0.00	0.51	30.08	294.11
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.56	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.14	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.22	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.14	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.08	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	1.02	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.83	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.21	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	2.50	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.11	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.15	0.00	0.00	0.00	0.00

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	0.04	0.00	0.00	0.00	0.00
WESTERN GRAVEL CONCRETE FACILITY	02MO0969	-944.266	-107.828	0.00	0.00	1.91	0.00	0.00	0.00	0.00
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	94MO198F	-937.525	-124.113	0.00	0.00	3.10	21.34	0.51	30.08	633.80
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	94MO198F	-937.525	-124.113	0.00	0.00	10.80	0.00	0.00	0.00	0.00
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	96MO843	-943.962	-108.507	0.00	0.00	0.33	0.00	0.51	30.08	294.11
OLDCASTLE SW GROUP DBA UNITED CO OF MESA	96MO843	-943.962	-108.507	0.00	0.00	0.34	0.00	0.51	30.08	294.11
RUSSELL STOVER CANDY	96MO947	-941.18	-113.486	0.00	3.48	0.00	10.67	0.76	13.20	477.44
RUSSELL STOVER CANDY	96MO947	-941.18	-113.486	0.00	0.00	0.39	10.67	0.76	13.20	477.44
RUSSELL STOVER CANDY	96MO947	-941.18	-113.486	0.39	0.00	0.00	10.67	0.76	13.20	477.44
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.00	6.70	0.00	6.10	0.61	12.47	477.44
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.00	0.00	0.19	6.10	0.61	12.47	477.44
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.19	0.00	0.00	6.10	0.61	12.47	477.44
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.00	0.00	0.81	0.00	0.51	30.08	294.11
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.00	0.00	6.66	0.00	0.51	30.08	294.11
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.00	0.00	4.20	0.00	0.51	30.08	294.11
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.00	0.00	0.41	0.00	0.51	30.08	294.11
INTERMOUNTAIN RESOURCES	97MO0921	-940.71	-107.176	0.00	0.00	0.68	0.00	0.51	30.08	294.11
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0186	-957.405	-102.783	0.39	-0.37	-1.52	15.24	0.91	1.10	633.80
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0186	-957.405	-102.783	0.00	12.67	0.00	0.00	0.00	0.00	0.00
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0187	-957.405	-102.783	0.00	1.68	0.00	15.24	0.91	1.10	633.80
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0187	-957.405	-102.783	0.00	5.58	0.00	15.24	0.91	1.10	633.80
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0187	-957.405	-102.783	0.00	0.00	0.07	0.00	0.00	0.00	0.00
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0187	-957.405	-102.783	0.00	0.00	0.04	15.24	0.91	1.10	633.80
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0187	-957.405	-102.783	0.00	0.00	0.02	15.24	0.91	1.10	633.80
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0187	-957.405	-102.783	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TRANSCOLORADO GAS TRANS OLATHE COM STA	98MO0187	-957.405	-102.783	0.01	0.00	0.00	0.00	0.00	0.00	0.00
TRANSCOLORADO GAS TRANS OLATHE COM STA	03MO0518	-957.405	-102.783	0.01	1.29	0.02	0.00	0.51	30.08	294.11
ASHES TO ASHES	99MO0581	-947.502	-108.068	-0.36	0.24	-0.02	0.00	0.51	30.08	294.11
ASHES TO ASHES	03MO0172	-947.502	-108.068	0.17	0.28	0.40	0.00	0.51	30.08	294.11
NICK H. GRAY - GRAY PIT #1	02MO0281F	-928.299	-111.063	0.00	0.00	0.16	0.00	0.51	30.08	294.11
NICK H. GRAY - GRAY PIT #1	02MO0281F	-928.299	-111.063	0.00	0.00	5.84	0.00	0.51	30.08	294.11
ENCANA OIL & GAS - NATURITA CREEK	03MO0290	-976.093	-141.423	0.01	4.38	0.62	7.62	0.43	12.04	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0291	-976.093	-141.423	0.00	7.76	0.00	7.93	0.43	16.00	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0291	-976.093	-141.423	0.00	4.56	0.00	7.93	0.43	16.00	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0291	-976.093	-141.423	0.00	0.00	0.55	7.93	0.43	16.00	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0291	-976.093	-141.423	0.00	0.00	0.55	7.93	0.43	16.00	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0291	-976.093	-141.423	0.01	0.00	0.00	7.93	0.43	16.00	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0291	-976.093	-141.423	0.01	0.00	0.00	7.93	0.43	16.00	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0292	-976.093	-141.423	0.01	12.02	0.85	7.62	0.43	16.00	633.80
ENCANA OIL & GAS - NATURITA CREEK	03MO0979	-976.093	-141.423	0.01	1.34	0.19	1.22	0.08	29.51	633.80
TRANSCOLORADO GAS TRANS - REDVALE CS	03MO1027	-994.966	-139.564	0.04	28.06	0.80	7.62	0.46	96.68	633.80
TRANSCOLORADO GAS TRANS - REDVALE CS	03MO1028	-994.966	-139.564	0.00	3.18	0.04	7.62	0.25	22.68	633.80
TRANSCOLORADO GAS TRANS - REDVALE CS	03MO1029	-994.966	-139.564	0.00	1.45	0.04	7.62	0.25	22.68	633.80
SUNSET MESA FUNERAL DIRECTORS	06MO0014	-942.999	-110.032	0.20	0.32	0.48	6.10	0.52	6.10	1144.11
SUNSET MESA FUNERAL DIRECTORS	06MO0014	-990.9	-141.124	0.00	0.00	0.11	0.00	0.00	0.00	0.00
SUNSET MESA FUNERAL DIRECTORS	06MO0014	-990.9	-141.124	0.00	0.00	4.64	0.00	0.00	0.00	0.00
SUNSET MESA FUNERAL DIRECTORS	06MO0014	-950.958	-91.208	0.00	0.00	0.30	0.00	0.00	0.00	0.00
SUNSET MESA FUNERAL DIRECTORS	06MO0014	-950.958	-91.208	0.00	0.00	0.21	0.00	0.00	0.00	0.00
SUNSET MESA FUNERAL DIRECTORS	06MO0014	-950.958	-91.208	0.00	0.00	0.42	0.00	0.00	0.00	0.00
ALLEN DRILLING - ALLEN PIT	06PA0448F	-769.424	-51.495	0.00	0.00	0.17	0.00	0.51	30.08	295.22
ALLEN DRILLING - ALLEN PIT	06PA0448F	-769.424	-51.495	0.00	0.00	5.25	0.00	0.51	30.08	295.22
ALLEN DRILLING - ALLEN PIT	06PA0448F	-769.424	-51.495	0.00	0.00	0.12	0.00	0.00	0.00	0.00
ALLEN DRILLING - ALLEN PIT	06PA0448F	-769.424	-51.495	0.00	0.00	1.91	0.00	0.00	0.00	0.00
CHEVRON USA - WILSON CREEK GAS PLT	97RB0187	-922.52	77.022	0.00	4.40	0.07	4.57	0.20	32.83	866.33
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	1.68	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	1.75	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.02	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.60	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.42	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.49	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.25	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.01	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.36	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	0.15	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	2.10	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-2	-990.248	85.476	0.00	0.00	3.54	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-5	-990.248	85.476	0.00	0.00	0.12	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	12RB802-6	-990.248	85.476	0.00	0.00	0.01	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	03RB0569F	-990.248	85.476	0.00	0.00	837.18	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	03RB0570	-990.248	85.476	0.00	0.00	0.60	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	03RB0570	-990.248	85.476	0.00	0.00	12.81	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	03RB0570	-990.248	85.476	0.00	0.00	2.10	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	03RB0570	-990.248	85.476	0.00	0.00	0.24	0.00	0.51	30.08	294.11
BLUE MOUNTAIN ENERGY - DESERADO MINE	03RB0570	-990.248	85.476	0.00	0.00	3.54	0.00	0.51	30.08	294.11
ENCANA OIL & GAS (USA) INC- E DRAGON TR	95RB676-2	-1001.181	46.363	0.00	1.08	0.00	7.32	0.24	35.24	824.11
ENCANA OIL & GAS (USA) INC- E DRAGON TR	95RB676-2	-1001.181	46.363	0.00	0.00	0.29	7.32	0.24	35.24	824.11
ENCANA OIL & GAS (USA) INC- E DRAGON TR	95RB676-2	-1001.181	46.363	0.02	0.00	0.00	7.32	0.24	35.24	824.11
ENCANA OIL & GAS (USA) INC- E DRAGON TR	13RB270-1	-1001.181	46.363	0.00	-1.65	0.00	7.01	0.21	58.13	766.33
ENCANA OIL & GAS (USA) INC- E DRAGON TR	13RB270-2	-1001.181	46.363	0.00	-2.44	0.00	7.01	0.21	58.13	766.33
ENCANA OIL & GAS (USA) INC- E DRAGON TR	99RB0024	-1001.181	46.363	0.02	2.90	0.29	0.00	0.51	30.08	294.11
ETC CANYON PIPELINE - N. DOUGLAS CREEK	13RB011	-997.633	59.464	0.00	28.00	0.00	5.49	0.37	30.08	755.22
ETC CANYON PIPELINE - N. DOUGLAS CREEK	13RB011	-997.633	59.464	0.00	0.00	0.49	5.49	0.37	30.08	755.22
ETC CANYON PIPELINE - N. DOUGLAS CREEK	13RB011	-997.633	59.464	0.03	0.00	0.00	5.49	0.37	30.08	755.22
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0685	-1002.979	29.082	0.00	-57.92	0.01	4.57	0.31	30.08	755.22
ETC CANYON PIPELINE-FOUNDATION CREEK	95RB617-3	-1002.979	29.082	0.00	24.40	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	95RB617-3	-1002.979	29.082	0.00	32.40	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0684	-1002.979	29.082	0.00	0.00	0.45	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0684	-1002.979	29.082	0.00	0.00	0.59	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0684	-1002.979	29.082	0.03	0.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0684	-1002.979	29.082	0.04	0.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0684	-1002.979	29.082	0.00	24.40	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0684	-1002.979	29.082	0.00	32.40	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0686	-1002.979	29.082	0.00	0.00	0.45	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0686	-1002.979	29.082	0.00	0.00	0.59	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0686	-1002.979	29.082	0.03	0.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	03RB0686	-1002.979	29.082	0.04	0.00	0.00	0.00	0.00	0.00	0.00
ETC CANYON PIPELINE-FOUNDATION CREEK	95RB617-1	-1002.979	29.082	0.00	2.50	0.00	9.14	1.52	30.08	1088.56
NORTHWEST PIPELINE CORP RANGELY STA		-996.465	70.009	-0.64	-320.86	3.41	4.27	0.61	30.08	671.89
NATURAL SODA	86RB140-9	-962.894	53.417	0.02	0.00	-0.02	15.24	1.22	30.08	352.44

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
NATURAL SODA	86RB140-9	-962.894	53.417	0.00	0.00	0.07	15.24	1.22	30.08	352.44
ENCANA OIL & GAS (USA) INC-W DOUGLAS CR	96RB347-2	-998.979	43.943	-0.01	-11.10	0.64	6.40	0.46	18.04	699.67
ENCANA OIL & GAS (USA) INC-W DOUGLAS CR	96RB347-3	-998.979	43.943	0.00	-10.80	0.67	9.75	0.31	18.04	633.80
ENCANA OIL & GAS (USA) INC-W DOUGLAS CR	96RB347-4	-998.979	43.943	-0.01	-11.90	0.59	9.75	0.31	18.04	633.80
CHEVRON USA PRODUCTION CO RANGELY FIELD	88RB066	-1004.485	76.758	0.00	0.15	0.00	8.23	0.61	8.35	533.00
CHEVRON USA PRODUCTION CO RANGELY FIELD	88RB066	-1004.485	76.758	0.00	0.26	0.00	6.71	0.52	12.25	533.00
CHEVRON USA PRODUCTION CO RANGELY FIELD	88RB066-8	-1004.485	76.758	0.00	0.29	0.00	6.40	0.52	12.25	560.78
CHEVRON USA PRODUCTION CO RANGELY FIELD	88RB066-9	-1004.485	76.758	0.00	4.85	0.00	5.49	0.61	8.26	560.78
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	92RB514	-1002.667	46.342	0.01	6.12	0.25	17.37	0.52	5.67	571.33
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL		-1002.667	46.342	0.00	92.00	0.00	4.88	0.25	26.64	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL		-1002.667	46.342	0.00	0.00	0.50	4.88	0.25	26.64	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL		-1002.667	46.342	0.01	0.00	0.00	4.88	0.25	26.64	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL		-1002.667	46.342	0.00	-0.80	0.19	7.62	0.31	17.62	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL		-1002.667	46.342	0.00	-0.80	0.19	7.62	0.31	17.62	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-4	-1002.667	46.342	0.00	0.57	0.37	7.62	0.31	29.84	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB026-2	-1002.667	46.342	0.00	51.10	0.00	7.62	0.76	13.11	552.44
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB026-2	-1002.667	46.342	0.00	0.00	4.80	7.62	0.76	13.11	552.44
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB026-2	-1002.667	46.342	0.06	0.00	0.00	7.62	0.76	13.11	552.44
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB026-3	-1002.667	46.342	0.00	-0.24	3.96	7.62	0.76	5.30	552.44
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-6	-1002.667	46.342	0.00	15.10	1.01	6.10	0.36	16.73	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-7	-1002.667	46.342	0.00	21.24	0.00	10.67	0.25	44.81	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-7	-1002.667	46.342	0.00	0.00	0.79	10.67	0.25	44.81	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-7	-1002.667	46.342	0.02	0.00	0.00	10.67	0.25	44.81	671.89
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-8	-1002.667	46.342	0.01	0.81	15.97	7.62	0.40	21.12	588.56
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-9	-1002.667	46.342	0.00	4.20	0.00	15.24	0.31	0.43	810.78
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-9	-1002.667	46.342	0.00	0.00	8.95	6.10	0.24	26.73	588.56
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-9	-1002.667	46.342	0.00	0.00	9.05	15.24	0.31	0.43	810.78
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-9	-1002.667	46.342	0.00	0.00	0.00	6.10	0.24	26.73	588.56
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-9	-1002.667	46.342	0.02	0.00	0.00	15.24	0.31	0.43	810.78
ENCANA OIL & GAS (USA) INC-DRAGON TRAIL	88RB376-9	-1002.667	46.342	0.00	0.88	0.00	15.24	0.31	0.43	810.78
SOURCE GAS DBA ROCKY MTN N.G.-PICEANCE	92RB1423-2	-953.696	62.924	0.00	1.44	0.00	3.66	0.09	26.15	644.11
SOURCE GAS DBA ROCKY MTN N.G.-PICEANCE	92RB1423-2	-953.696	62.924	0.00	16.99	0.00	0.00	0.00	0.00	0.00
SOURCE GAS DBA ROCKY MTN N.G.-PICEANCE	92RB1423-2	-953.696	62.924	0.00	0.00	0.03	3.66	0.09	26.15	644.11
SOURCE GAS DBA ROCKY MTN N.G.-PICEANCE	92RB1423-2	-953.696	62.924	0.00	0.00	0.06	0.00	0.00	0.00	0.00
WRR SAND & GRAVEL - BLAIR MESA PIT	91RB043F	-959.234	78.069	0.00	0.00	9.79	0.00	0.51	30.08	294.11
COLORADO INTERSTATE GAS CO GREASEWOOD	94RB420-1	-949.499	48.205	0.00	12.90	0.00	5.49	0.31	19.63	578.00
COLORADO INTERSTATE GAS CO GREASEWOOD	94RB420-1	-949.499	48.205	0.00	0.00	1.20	5.49	0.31	19.63	578.00
COLORADO INTERSTATE GAS CO GREASEWOOD	94RB420-1	-949.499	48.205	0.03	0.00	0.00	5.49	0.31	19.63	578.00
COLORADO INTERSTATE GAS CO GREASEWOOD	94RB420-2	-949.499	48.205	0.03	12.90	1.20	5.49	0.31	29.20	294.11
COLORADO INTERSTATE GAS CO GREASEWOOD	05RB0312	-949.499	48.205	0.43	88.89	0.89	12.19	1.02	2.59	621.33
PUBLIC SERVICE COMPANY INDIAN VALLEY STA	06RB0801	-949.81	69.633	0.01	7.42	0.50	7.01	0.37	9.39	513.56
ENCANA OIL & GAS (USA) INC.- W DRAGON T	93RB341-3	-1008.241	50.378	0.00	28.03	0.00	5.79	0.15	30.08	794.67
ENCANA OIL & GAS (USA) INC.- W DRAGON T	93RB341-3	-1008.241	50.378	0.00	0.00	0.07	5.79	0.15	30.08	794.67
ENCANA OIL & GAS (USA) INC.- W DRAGON T	93RB341-3	-1008.241	50.378	0.00	0.00	0.00	5.79	0.15	30.08	794.67
ENCANA OIL & GAS (USA) INC.- W DRAGON T	99RB0037	-1008.241	50.378	0.00	14.16	0.00	1.83	0.37	36.79	633.80
ENCANA OIL & GAS (USA) INC.- W DRAGON T	99RB0037	-1008.241	50.378	0.00	0.00	0.26	1.83	0.37	36.79	633.80
ENCANA OIL & GAS (USA) INC.- W DRAGON T	99RB0037	-1008.241	50.378	0.02	0.00	0.00	1.83	0.37	36.79	633.80
PUBLIC SERVICE CO GREASEWOOD STATION	04RB1290	-949.523	48.134	0.00	30.60	0.10	9.14	0.35	29.11	855.22
WHITE RIVER SAND & GRAVEL-MEEKER PIT	91RB410	-921.615	59.555	0.00	0.00	0.81	0.00	0.00	0.00	0.00
WHITE RIVER SAND & GRAVEL-MEEKER PIT	91RB410	-921.615	59.555	0.00	0.00	0.20	0.00	0.00	0.00	0.00
WHITE RIVER SAND & GRAVEL-MEEKER PIT	91RB410	-921.615	59.555	0.00	0.00	0.90	0.00	0.00	0.00	0.00
LAFARGE WEST INC. - BLAIR MESA MINE	96RB890F	-959.959	78.952	0.00	0.00	0.07	0.00	0.51	30.08	294.11
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	4.06	0.00	7.62	0.31	49.44	734.67
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	25.88	0.00	0.00	0.00	0.00	0.00
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	0.00	0.00	7.62	0.31	49.44	734.67
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.02	0.00	0.00	7.62	0.31	49.44	734.67
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.03	0.00	0.00	0.00	0.00	0.00	0.00
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	3.48	0.00	7.62	0.31	49.44	734.67
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	25.88	0.00	0.00	0.00	0.00	0.00
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	0.00	0.00	7.62	0.31	49.44	734.67
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.02	0.00	0.00	7.62	0.31	49.44	734.67
WEST TEXAS - PICEANCE CREEK GP	98RB0713	-949.616	47.298	0.03	0.00	0.00	0.00	0.00	0.00	0.00
WEST TEXAS - PICEANCE CREEK GP	07RB0772	-949.616	47.298	0.02	17.25	0.29	10.67	2.44	87.02	723.00
WEST TEXAS - PICEANCE CREEK GP	07RB0775	-949.616	47.298	0.00	26.28	0.44	7.62	2.44	115.82	699.67
EXXON MOBIL CORPORATION - LOVE RANCH	02RB0733	-957.969	47.388	0.00	9.40	0.34	6.10	0.31	34.75	710.78
EXXON MOBIL CORPORATION - LOVE RANCH	02RB0963	-957.969	47.388	0.00	3.20	0.00	15.24	0.20	37.49	676.89
SOUTH-TEX TREATERS INC. - MEEKER PLANT	02RB0217	-946.972	69.709	0.00	21.90	0.00	7.32	0.34	44.62	866.33
SOUTH-TEX TREATERS INC. - MEEKER PLANT	02RB0217	-946.972	69.709	0.00	0.00	0.05	7.32	0.34	44.62	866.33
SOUTH-TEX TREATERS INC. - MEEKER PLANT	02RB0217	-946.972	69.709	0.03	0.00	0.00	7.32	0.34	44.62	866.33
SOUTH-TEX TREATERS INC. - MEEKER PLANT	02RB0217	-946.972	69.709	0.04	21.90	0.58	7.32	0.35	62.24	916.33
ENCANA OIL & GAS (USA) INC - BULL FORK	07RB0471	-960.057	26.171	0.03	24.40	0.00	7.62	0.31	233.69	738.00
ENCANA OIL & GAS (USA) INC - BULL FORK	07RB0471	-960.057	26.171	0.00	19.20	0.00	0.00	0.00	0.00	0.00
ENCANA OIL & GAS (USA) INC - BULL FORK	07RB0471	-960.057	26.171	0.00	19.40	0.00	0.00	0.00	0.00	0.00
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.02	17.00	0.39	8.53	0.31	49.68	633.80
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.00	22.10	0.00	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.00	17.00	0.00	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.00	0.00	0.38	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.00	0.00	0.39	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.02	0.00	0.00	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.02	0.00	0.00	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.02	17.00	1.90	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.02	17.00	0.38	8.53	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.02	17.00	0.39	9.14	0.31	46.42	738.00
BARGATH INC - GREASEWOOD CS	03RB1191	-949.519	46.708	0.02	17.00	0.39	9.14	0.31	49.68	730.22
BARGATH INC - GREASEWOOD CS	03RB1191	-1020.469	54.352	0.00	0.02	0.00	0.00	0.00	0.00	0.00
BARGATH INC - GREASEWOOD CS	03RB1191	-1019.65	54.632	0.00	0.01	0.00	0.00	0.00	0.00	0.00
ENCANA (WEST) - LHDU 2194	04RB0807	-1012.315	49.237	0.00	18.30	0.03	6.10	0.24	36.58	810.78
ENCANA (WEST) - LHDU 2111	04RB0808	-1011.855	49.608	0.00	18.30	0.03	6.10	0.24	36.58	810.78
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.00	10.00	0.00	4.27	0.31	46.88	727.44
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.00	0.00	0.28	0.00	0.00	0.00	0.00
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.00	0.00	0.15	4.27	0.31	46.88	727.44
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.02	0.00	0.00	0.00	0.00	0.00	0.00
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.01	0.00	0.00	4.27	0.31	46.88	727.44
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.01	11.50	0.15	7.62	0.44	13.05	533.00
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.00	11.50	0.00	0.00	0.00	0.00	0.00
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.01	7.40	0.10	7.32	0.25	24.93	521.89
BARGATH INC - RYAN GULCH GAS	04RB1052	-961.73	48.615	0.02	16.60	0.36	7.62	0.31	46.42	738.00

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	Stack Temperature (K)
GAS TECHNOLOGY CORP. - YELLOW CREEK PLT.	04RB1281	-960.889	59.501	0.01	1.00	0.13	0.00	0.51	30.08	294.11
GAS TECHNOLOGY CORP. - YELLOW CREEK PLT.	04RB1281	-960.889	59.501	0.01	1.00	0.13	6.10	0.15	46.91	875.22
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0032	-975.061	45.249	0.03	19.40	0.00	7.62	0.31	49.71	633.80
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0033	-975.061	45.249	0.00	19.40	0.00	7.62	0.31	49.71	633.80
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0129	-975.061	45.249	0.03	31.00	0.49	7.62	0.34	43.43	671.89
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0130	-975.061	45.249	0.02	14.00	0.25	9.14	0.20	45.45	633.80
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0130	-975.061	45.249	0.00	14.00	0.00	0.00	0.00	0.00	0.00
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0131	-975.061	45.249	0.00	12.61	0.00	7.62	0.31	45.45	793.00
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0131	-975.061	45.249	0.00	0.00	0.25	0.00	0.00	0.00	0.00
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0131	-975.061	45.249	0.00	0.00	0.36	7.62	0.31	45.45	793.00
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0131	-975.061	45.249	0.02	0.00	0.00	0.00	0.00	0.00	0.00
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	05RB0131	-975.061	45.249	0.02	0.00	0.00	7.62	0.31	45.45	793.00
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	07RB0615	-975.061	45.249	0.00	19.50	0.40	6.40	3.66	49.68	730.22
WILGATH (FORMERLY ROC GAS) - SAGEBRUSH	07RB0815	-959.993	55.055	0.00	60.70	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0223	-959.993	55.055	0.00	35.10	0.00	15.24	1.74	0.12	810.78
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0223	-959.993	55.055	0.00	0.00	4.52	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0223	-959.993	55.055	0.00	0.00	15.20	15.24	1.74	0.12	810.78
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0223	-959.993	55.055	0.36	0.00	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0223	-959.993	55.055	0.00	29.30	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0224	-959.993	55.055	0.00	0.70	0.00	12.19	1.28	4.18	810.78
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0224	-959.993	55.055	0.00	0.00	11.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0224	-959.993	55.055	0.00	0.08	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0228	-959.993	55.055	0.00	5.60	0.00	12.19	0.31	20.00	1271.89
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0279	-959.993	55.055	0.00	35.10	15.20	15.24	1.74	20.00	810.78
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0852	-959.993	55.055	0.00	0.70	0.00	12.19	1.28	4.18	810.78
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0884	-959.993	55.055	0.00	5.60	0.00	12.19	0.31	20.00	1271.89
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0884	-1019.262	54.597	0.00	0.02	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0884	-1020.043	54.706	0.00	0.01	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS PROC - MEEKER GAS PLANT	05RB0884	-1023.032	37.324	0.00	5.10	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS-PICEANCE DEV. PROJECT	05RB0896	-958.596	43.125	0.00	0.40	0.40	0.00	0.51	30.08	294.11
ENTERPRISE GAS-PICEANCE DEV. PROJECT	05RB0896	-958.596	43.125	0.00	1.50	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS-PICEANCE DEV. PROJECT	05RB0896	-958.596	43.125	0.09	16.40	1.30	0.00	0.51	30.08	294.11
ENTERPRISE GAS-PICEANCE DEV. PROJECT	05RB0896	-958.596	43.125	0.20	9.95	0.30	0.00	0.51	30.08	294.11
ENTERPRISE GAS-PICEANCE DEV. PROJECT	05RB0896	-958.596	43.125	0.00	5.40	0.00	0.00	0.00	0.00	0.00
ENTERPRISE GAS-PICEANCE DEV. PROJECT	05RB0896	-958.596	43.125	0.00	1.80	0.00	0.00	0.00	0.00	0.00
SHELL FRONTIER - MAHOGANY RESEARCH PROJE	05RB0929	-984.47	49.471	0.20	0.00	0.00	15.24	0.18	3.84	840.22
SOUTH-TEX - BASS YELLOW CREEK	06RB0761	-960.599	61.298	0.00	1.07	0.00	0.00	0.51	30.08	294.11
SOUTH-TEX - BASS YELLOW CREEK	06RB0761	-960.599	61.298	0.00	13.52	0.00	0.00	0.51	30.08	294.11
COLOWYO COAL CO-RTEA SOUTH TAYLOR PROJEC	06RB1317	-916.841	75.349	0.00	0.00	685.00	0.00	0.51	30.08	295.22
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-949.812	69.639	0.00	0.00	0.17	0.00	0.51	30.08	294.11
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-949.812	69.639	0.00	0.00	18.63	0.00	0.51	30.08	294.11
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-982.225	72.787	0.00	2.31	0.00	0.00	0.00	0.00	0.00
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-982.225	72.787	0.00	0.12	0.00	0.00	0.00	0.00	0.00
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-982.225	72.787	0.00	23.20	0.00	0.00	0.00	0.00	0.00
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-929.964	51.928	0.00	0.00	6.05	0.00	0.00	0.00	0.00
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-929.964	51.928	0.00	0.00	4.57	0.00	0.00	0.00	0.00
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-946.617	74.268	0.00	6.23	0.00	0.00	0.00	0.00	0.00
CONNELL RESOURCES - WHITE RIVER CITY PIT	06RB1069F	-946.314	73.426	0.00	6.23	0.00	0.00	0.00	0.00	0.00
XTO ENERGY INC. - SHULTS GRAVEL PIT	07RB0554	-940.308	58.306	0.36	3.40	0.39	3.05	0.23	30.08	633.80
XTO ENERGY INC. - SHULTS GRAVEL PIT	07RB0554	-940.308	58.306	0.00	0.00	0.60	0.00	0.00	0.00	0.00
XTO ENERGY INC. - SHULTS GRAVEL PIT	07RB0554	-940.308	58.306	0.00	0.00	2.18	0.00	0.00	0.00	0.00
XTO ENERGY INC. - SHULTS GRAVEL PIT	07RB0553	-940.308	58.306	0.96	2.79	0.11	3.05	0.23	30.08	633.80
CONOCOPHILLIPS CO - TEMP LIVING QUARTERS	07RB0732	-945.677	24.617	2.90	87.90	0.90	4.57	0.51	81.96	783.00
MATHIAS CONCRETE INC - NORTH FARM ROAD	02RG0503F	-801.634	-223.384	0.00	0.00	0.97	0.00	0.51	30.08	294.11
MATHIAS CONCRETE INC - NORTH FARM ROAD	02RG0503F	-801.634	-223.384	0.00	0.00	0.02	0.00	0.51	30.08	294.11
MATHIAS CONCRETE - SOUTH FORK	89RG411-1F	-804.587	-208.257	0.00	0.00	0.92	0.00	0.00	0.00	0.00
MATHIAS CONCRETE - SOUTH FORK	89RG411-1F	-804.587	-208.257	0.00	0.00	0.44	0.00	0.00	0.00	0.00
MATHIAS CONCRETE - SOUTH FORK	89RG411-1F	-804.587	-208.257	0.00	0.00	0.43	0.00	0.00	0.00	0.00
ASPHALT CONSTRUCTORS INC -DEL NORTE WEST	02RG0464F	-817.071	-212.625	0.00	0.00	1.47	0.00	0.51	30.08	294.11
ASPHALT CONSTRUCTORS INC -DEL NORTE WEST	02RG0464F	-817.071	-212.625	0.00	0.00	3.67	0.00	0.51	30.08	294.11
PUBLIC SERVICE CO - DEL NORTE STATION	03RG0576	-821.736	-214.938	0.00	2.54	0.01	10.36	0.31	34.78	841.33
PUBLIC SERVICE CO HAYDEN PLT	10RO173	-857.326	101.903	-19.50	-355.40	3.30	120.40	7.32	10.79	417.44
PUBLIC SERVICE CO HAYDEN PLT	13RO598	-857.326	101.903	0.00	0.00	4.80	0.00	0.51	30.08	294.11
PUBLIC SERVICE CO HAYDEN PLT	96RO551-1	-857.326	101.903	0.00	0.00	0.70	0.00	0.51	30.08	294.11
PUBLIC SERVICE CO HAYDEN PLT	98RO0375	-857.326	101.903	0.00	0.00	0.21	4.88	0.21	7.25	294.11
PUBLIC SERVICE CO HAYDEN PLT		-857.326	101.903	0.12	1.86	0.13	5.49	0.15	30.08	633.80
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	6.56	0.00	0.00	0.00	0.00
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	11.07	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.02	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.05	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.07	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	7.40	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.02	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	1.47	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.58	0.00	0.00	0.00	0.00
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.04	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.29	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	30.46	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.04	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.06	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.03	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.03	0.00	0.00	0.00	0.00
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.00	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.03	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.03	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.00	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.01	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	1.54	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK		-849.781	85.351	0.00	0.00	5.61	0.00	0.51	30.08	294.11
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.07	0.00	0.51	30.08	295.22
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.02	0.00	0.51	30.08	295.22
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.02	0.00	0.51	30.08	295.22
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.12	0.00	0.51	30.08	295.22

Table B4.1.2: Colorado Included Permitted Industrial Sources (continued)

Facility	Permit	X_{LCP} (km)	Y_{LCP} (km)	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Diameter (m)	Stack Velocity (m/s)	St Temp (
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.07	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.03	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	4.88	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.02	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.76	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.05	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.05	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	17.52	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.00	0.00	0.51	30.08	
TWENTYMILE COAL CO.- FOIDEL CREEK	93RO1204	-849.781	85.351	0.00	0.00	0.05	0.00	0.51	30.08	
HAYDEN GULCH TERMINAL INC	05RO0020	-867.807	89.324	0.00	0.00	70.00	0.00	0.51	30.08	
HAYDEN GULCH TERMINAL INC	05RO0020	-867.807	89.324	0.00	0.00	1.02	0.00	0.51	30.08	
TRANS COLO CONCRETE	90RO192	-829.562	100.468	0.00	0.00	0.32	0.00	0.51	30.08	
TRANS COLO CONCRETE	90RO192	-829.562	100.468	0.00	0.00	0.58	0.00	0.51	30.08	
PRECISION EXCA-CAMILLETTI MILNER #2 PIT	00RO0741F	-843.148	98.724	0.00	0.00	0.78	0.00	0.51	30.08	
PRECISION EXCA-CAMILLETTI MILNER #2 PIT	00RO0741F	-843.148	98.724	0.00	0.00	27.53	0.00	0.51	30.08	
PRECISION EXCA-CAMILLETTI MILNER #2 PIT	00RO0741F	-843.148	98.724	0.00	0.00	0.17	0.00	0.00	0.00	
PRECISION EXCA-CAMILLETTI MILNER #2 PIT	00RO0741F	-843.148	98.724	0.00	0.00	0.02	0.00	0.00	0.00	
STEAMBOAT SPRINGS ANIMAL SHELTER	04RO0696	-829.209	99.11	0.13	0.21	0.36	0.00	0.51	30.08	
KING MOUNTAIN GRAVEL	05RO0295F	-837.936	51.387	0.00	0.00	0.85	0.00	0.51	30.08	
FOREST OIL CORP-WOLF MTN	05RO0546	-851.717	110.179	0.00	13.10	0.04	0.00	0.51	211.23	
OLDCASTLE SW GROUP DBA TELLURIDE GRAVEL	07SM0826	-950.787	-169.781	0.00	0.00	0.30	0.00	0.51	30.08	
OLDCASTLE SW GROUP DBA TELLURIDE GRAVEL	07SM0826	-950.787	-169.781	0.00	0.00	1.74	0.00	0.00	0.00	
ENCANA - ANDY'S MESA	04SM0659	-1013.598	-150.928	0.03	17.50	0.45	69.49	3.66	43.53	
ENCANA - ANDY'S MESA	05SM0332	-1013.598	-150.928	0.03	21.40	0.56	4.57	0.31	30.08	
ENCANA - ANDY'S MESA	05SM0332	-1013.598	-150.928	0.00	21.41	0.00	0.00	0.00	0.00	
ENCANA OIL & GAS - HAMILTON CREEK BOOSTE	04SM0703	-996.077	-144.251	0.01	14.40	0.13	6.71	0.34	14.05	
ENCANA OIL & GAS - HAMILTON CREEK BOOSTE	04SM0703	-996.077	-144.251	0.03	21.40	0.56	6.71	0.34	43.65	
CABOT OIL & GAS - DOUBLE EAGLE PLANT	01SM0730	-1013.944	-150.443	0.00	-12.10	0.01	9.14	0.24	14.60	
CABOT OIL & GAS - DOUBLE EAGLE PLANT	01SM0804	-1013.944	-150.443	0.00	52.86	0.03	6.10	0.24	9.60	
CABOT OIL & GAS - FOSSIL FEDERAL #4-20	03SM1053	-1015.604	-148.996	0.00	3.60	0.07	4.57	0.15	25.91	
CABOT OIL & GAS - FOSSIL FEDERAL 8	03SM1112	-1018.038	-147.359	0.01	5.19	0.11	3.05	0.31	6.43	
CABOT OIL & GAS - FOSSIL FEDERAL 8	03SM1112	-1018.038	-147.359	0.00	5.70	0.00	0.00	0.00	0.00	
ENCANA (WEST) - HAMILTON CREEK CS	05SM0106	-997.861	-145.435	0.00	0.70	0.00	0.00	0.51	30.08	
ENCANA (WEST) - HAMILTON CREEK CS	05SM0108	-997.861	-145.435	0.03	17.10	0.46	6.71	0.31	30.08	
ENCANA (WEST) - HAMILTON CREEK CS	05SM0109	-997.861	-145.435	0.03	17.10	0.46	6.71	0.34	41.09	
ENCANA (WEST) - HAMILTON CREEK CS	05SM0110	-997.861	-145.435	0.03	17.10	0.46	6.71	0.34	41.09	
ENCANA (WEST) - HAMILTON CREEK CS	05SM0111	-997.861	-145.435	0.01	10.00	0.00	6.71	0.34	31.70	
ENCANA (WEST) - HAMILTON CREEK CS	05SM0182	-997.861	-145.435	0.03	17.10	0.46	6.71	0.34	41.09	
ENCANA (WEST) - HAMILTON CREEK CS	06SM0683	-997.861	-145.435	0.00	1.00	0.00	0.00	0.51	30.08	
ENCANA (WEST) - HAMILTON CREEK CS	06SM0684	-997.861	-145.435	0.00	19.38	0.00	6.71	0.61	30.08	
COPPER MTN RESORT SOLITUDE STA	87SU303I	-782.234	-17.457	0.08	0.10	0.16	8.23	0.67	10.06	
COPPER MTN RESORT SOLITUDE STA	87SU303I	-782.234	-17.457	0.00	0.25	0.01	8.23	0.67	10.06	
ENCANA (WEST) - PORT COMP ENG CE-P19	05PO0963	-953.179	-33.559	0.00	18.18	0.00	7.62	0.31	49.77	

Table B4.1.3: Wyoming Included Permitted Industrial Sources

County	X_{LCP}	Y_{LCP}	Facility	Permit	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Carbon	-893.65314	197.07568	Baggs Mainline/ Blue Gap Compressor Station	MD-1027	0	36.5	0	0	0	0	0
Carbon	-884.21893	194.46631	Blue Sky	MD-950	0	46.1	0	11	730	71.6	0.25
Carbon	-885.92059	203.84082	Cow Creek Central Production Facility	wv-0551	0	49.5	0	0	0	0	0
Carbon	-886.08551	203.62207	Cow Creek Unit 34-12	MD-1043A	0	29.3	0	0	0	0	0
Carbon	-878.68256	210.71484	Doty Mountain Compressor Station	MD-1071	0	64.2	0	0	0	0	0
Carbon	-894.67627	232.73877	Echo Springs Compressor Station	MD-1123	0	87.4	0	0	0	0	0
Carbon	-894.74805	232.76074	Echo Springs Samson Dehydrator Station	CT-3590	0	4.6	0	0	0	0	0
Carbon	-883.40399	203.98633	Federal 1691 8I Injection Well	wv-0505	0	66.6	0	0	0	0	0
Carbon	-819.1424	231.89453	Jons/Ruth Sweezy Compressor Station	MD-941	0	8.1	0	0	0	0	0
Carbon	-905.94397	190.82129	Snow Bank	CT-3778	0	30	0	0	0	0	0
Carbon	-895.15881	165.95703	South Baggs Compressor Station	MD-1036	0	51.7	0	0	0	0	0
Carbon	-897.42944	225.27686	Standard Draw 5-10	wv-5U2	0	5.9	0	0	0	0	0
Carbon	-883.70105	201.13037	Sun Dog CBM Unit Pod 6	MD-1092	0	33.4	0	0	0	0	0
Carbon	-879.83661	190.42627	Wild Cow Compressor Station	CT-3634	0	4.5	0	0	0	0	0
Carbon County Total					0	517.8	0				
Sweetwater	-914.84955	190.43311	Church Butte	CT-2739	0	20	0	0	0	0	0
Sweetwater	-914.00287	186.48291	Dripping Rock Compressor Station	MD-780	0	14.3	0	0	0	0	0
Sweetwater	-910.21021	239.67139	Frewan Lake Compressor Station	MD-1242	0	15.9	0	0	0	0	0
Sweetwater	-946.44934	227.74805	Higgins Dehydration Facility	CT-4008	74.4	0.9	0	0	0	0	0
Sweetwater	-981.07227	200.70117	Pacific Rim Generator Station #1	CT-3472	0	10.5	0	9.05	509.82	12.5	0.76
Sweetwater	-976.76459	196.9248	Rifes Rim Compressor Station #1	CT-4072	0	10.5	0	0	0	0	0
Sweetwater	-1015.6532	218.31543	Rock Springs Station	MD-1006	0	3.1	0	0	0	0	0
Sweetwater	-912.16785	219.60986	Wild Rose Compressor Station	CT-3412	0	120.6	0	6.7	903.7	32.9	0.38
Sweetwater	-959.46082	231.8418	Yates Bicycle Federal Compressor #18	CT-3477	0	6.3	0	9.05	509.82	12.5	0.76
Sweetwater	-958.7243	234.61865	Yates Bicycle Federal Compressor #6	CT-3507	0	6.3	0	9.05	509.82	12.5	0.76
Sweetwater	-955.91718	230.94971	Yates Huffy State Compressor #16	CT-3508	0	6.3	0	9.05	509.82	12.5	0.76
Sweetwater County Total					74.4	214.7	0				
Uinta	-1126.9137	231.4707	Leroy Storage Compressor Station	MD-1049	0	3.5	0	0	0	0	0
Uinta County Total					0	3.5	0				

Table B4.1.3: Wyoming Included RFFA Sources

County	X_{LCP}	Y_{LCP}	Facility	Permit	SOx (tpy)	NOx (tpy)	PM_{10} (tpy)	Stack Height (m)	Stack Temperature (K)	Stack Velocity (m/s)	Stack Diameter (m)
Carbon	-894.33514	203.44092	Barrel Springs Compressor	wv-2254	0	3.8	0	0	0	0	0
Carbon	-879.45795	184.20654	Brown Cow Injection Facility	CT-4005	0	22.2	0	0	0	0	0
Carbon	-887.81958	163.92676	C&B Sand and Gravel Quarry	CT-3881	0	0	8	0	0	0	0
Carbon	-819.1424	231.89453	Carbon Basin Mines (CBM)	CT-4136	4.1	238.7	301.1	0	0	0	0
Carbon	-882.66583	229.84766	Carbon County Compressor Station	wv-0166	0	4.3	0	0	0	0	0
Carbon	-902.07593	214.42871	Champlin 444 A1	wv-2661(CORRECTED)	0	3.5	0	0	0	0	0
Carbon	-885.74689	228.36133	East Echo Springs 10-26-19-92	wv-AR2	0	5.3	0	0	0	0	0
Carbon	-902.08252	230.12695	Echo Springs Federal 4-30 PAD	wv-5244	0	3.1	0	0	0	0	0
Carbon	-893.08783	235.93457	Echo Springs Gas Plant	MD-1001	0	159.1	0	0	0	0	0
Carbon	-858.1853	225.8252	Espy Unit #3	wv-3478	0	3.6	0	0	0	0	0
Carbon	-884.23199	194.16064	Federal 1591 8I Injection Well	wv-0505	0	5	0	0	0	0	0
Carbon	-893.3996	216.26758	Federal 43-6	wv-1773	0	6.4	0	0	0	0	0
Carbon	-882.25067	230.21826	Fillmore 3-19	CT-2884	0	6.7	0	11.77	450.54	9.51	0.82
Carbon	-880.74658	228.42871	Fillmore 3-29	CT-3191	0	4	0	11.77	450.54	9.51	0.82
Carbon	-881.68054	229.12988	Fillmore Compressor Station	wv-XF2	0	8.1	0	0	0	0	0
Carbon	-864.36816	226.82764	Fillmore Federal 2-19	CT-3190	0	3.3	0	11.77	450.54	9.51	0.82
Carbon	-881.49677	229.2749	Fillmore Federal 2-20	CT-3265	0	3.4	0	11.77	450.54	9.51	0.82
Carbon	-882.96588	230.24023	Fillmore Federal 4-19	CT-3263	0	4.8	0	11.77	450.54	9.51	0.82
Carbon	-881.40588	230.04541	Fillmore Federal 4-20	MD-888	0	3.8	0	0	0	0	0
Carbon	-896.36591	169.45166	Gamblers Reservior Federal 43-32	wv-6774	0	2.7	0	0	0	0	0
Carbon	-847.85046	232.12158	Hatfield UPRR #2	wv-3946	0	1.6	0	0	0	0	0
Carbon	-871.7851	222.9126	Jolly Rogers Pod Compressor Station	MD-1063	0	58.5	0	0	0	0	0
Carbon	-879.71136	173.7583	Muddy Mountain Compressor Station	MD-1295	0	46.7	0	0	0	0	0
Carbon	-815.36902	207.40723	Portable Crushing and Screening Plant	CT-2933	0.2	3	0.7	11.68	326.21	15.37	0.73
Carbon	-859.42944	236.19824	Red Rim Compressor Station	MD-1065	0	70.5	0	0	0	0	0
Carbon	-901.92206	224.65674	Standard Draw 1-18-18-93	CT-3079	0	3.3	0	0	0	0	0
Carbon	-896.47607	223.95557	Standard Draw 14-3	CT-3042	0	3	0	0	0	0	0
Carbon	-865.19489	166.1416	State 34-13-89 #1	wv-3556	0	3.6	0	0	0	0	0
Carbon	-903.02466	187.21875	TBI Federal 10-09	CT-2684	2.8	2.4	0	0	0	0	0
Carbon	-790.91962	192.79199	TZ Pit	CT-3475	0	0	2.4	11.68	326.21	15.37	0.73
Carbon County Total					7.1	684.4	312.2				
Sweetwater	-971.37775	217.69531	11 Phosphoria Compressor Station	wv-FQ1	0	5.2	0	0	0	0	0
Sweetwater	-905.00806	216.45947	Barrel Springs Federal 12-1	wv-3933	0	2.9	0	0	0	0	0
Sweetwater	-973.38177	216.40869	Big Robbie Compressor Station	CT-3326	0	17.7	0	9.05	509.82	12.5	0.76
Sweetwater	-953.01575	228.95654	Bitter Creek Pit	CT-3967	0	3.7	3.8	0	0	0	0
Sweetwater	-942.39886	212.91895	Bitter Creek Zeolite Mine/Processing Plant	CT-3490	7.9	38	9.8	15	422	10	0.31
Sweetwater	-961.7287	232.11279	Black Bear 1	wv-3120	0	3.9	0	0	0	0	0
Sweetwater	-963.45508	225.56689	Black Butte 11-18-100 Compressor Station	CT-2605	0	7.7	0	9.14	422	39.62	0.25
Sweetwater	-960.27863	234.73584	Black Butte 1-18-100 Compressor Station	wv-SZ2	0	6	0	0	0	0	0
Sweetwater	-960.20251	231.90576	Black Butte 13-18-100 Compressor Station	CT-2606	0	5.8	0	9.14	422	39.62	0.25
Sweetwater	-962.13385	234.19971	Black Butte 23-19-100 Compressor Station	CT-2397A	0	1.9	0	0	0	0	0
Sweetwater	-975.93127	182.99854	Canyon Creek 11	CT-2556	0	1	0	0	0	0	0
Sweetwater	-975.29102	183.79492	Canyon Creek/Vermillion Complex	MD-605	0	34.1	0	15	422	10	0.31
Sweetwater	-905.97388	221.2793	Clyde Federal Pad Facility	wv-5243	0	3.1	0	0	0	0	0
Sweetwater	-943.79993	203.23779	Cooley Pit	CT-2218	0	0	14.8	0	0	0	0
Sweetwater	-880.07422	239.14941	Creston Junction Pit	CT-4322	0	0	1.2	0	0	0	0
Sweetwater	-923.698	167.65918	Fireplace Rock #1 Compressor Station	wv-XK2	0	1.9	0	0	0	0	0
Sweetwater	-1051.1676	216.80518	Green River Compressor Station	MD-1008	0	7.1	0	0	0	0	0
Sweetwater	-1054.18176	239.73486	Green River Soda Ash Plant	MD-1067	0	379.1	108.2	0	0	0	0
Sweetwater	-881.7926	237.75684	J & D Scoria Pit	CT-3891	0	0	1.1	0	0	0	0
Sweetwater	-916.9198	224.34229	KOP 40-22	wv-4450	0	2.3	0	0	0	0	0
Sweetwater	-1035.49353	233.31738	MH-1 Compressor Station	CT-2301	0	32.2	0	9.05	509.82	12.5	0.76
Sweetwater	-981.07227	200.70117	Pacific Rim Compressor Station #1	CT-3471	0	17.1	0	9.05	509.82	12.5	0.76
Sweetwater	-960.72784	232.68555	Pipeline 12-4-18-100	CT-4462	0	4.1	0	0	0	0	0
Sweetwater	-960.39307	232.06885	Pipeline 13-12-18-100	wv-2840	0	3.4	0	0	0	0	0
Sweetwater	-959.85028	234.27783	Pipeline 1-3-18-100	wv-2843	0	6.4	0	0	0	0	0
Sweetwater	-960.1748	231.93213	Pipeline 13-2-18-100	wv-2848	0	3.5	0	0	0	0	0
Sweetwater	-1000.50092	211.35449	Pretty Water Gas Plant	CT-2969	0	13.8	0	15	422	10	0.31
Sweetwater	-954.78278	223.91357	Pronghorn 3-3	wv-4258	0	3.4	0	0	0	0	0
Sweetwater	-929.12592	239.04346	Red Desert Gas Plant	MD-669	0	77.6	0	7.62	422	28.96	0.41
Sweetwater	-883.32825	237.96045	Red Rock Pit	CT-3975	0	0	2.8	0	0	0	0
Sweetwater	-881.7926	237.75684	Red Rock Pit/Hyland	CT-3946	0	0	4.5	0	0	0	0
Sweetwater	-1017.66437	237.73047	Rock Springs Complex (Clmn/Knda/Nghtngl)	wv-0613	0	3.4	0	0	0	0	0
Sweetwater	-1001.69153	237.11963	Rock Springs Facility	MD-1130	145.9	0	0	0	0	0	0
Sweetwater	-1003.65894	211.79492	South Baxter Compressor Station	CT-3730	0	13.8	0	0	0	0	0
Sweetwater	-942.33679	237.27393	Table Rock Gas Plant	MD-767	80.1	104.2	0	0	0	0	0
Sweetwater	-984.66406	197.97021	Union Federal2-11	wv-3779	0	1.9	0	0	0	0	0
Sweetwater	-970.17316	174.33838	Vermillion Creek Compressor Station	MD-549A	0	3.6	0	9.05	509.82	12.5	0.76
Sweetwater	-965.33679	185.04346	Vermillion Creek Deep Unit #1	wv-4185	0	3.7	0	0	0	0	0
Sweetwater	-910.21021	239.67139	Wamsutter Regulator	wv-XC2	0	6.8	0	0	0	0	0
Sweetwater	-913.664	211.08252	White Rock Pit South	CT-4057	0	0	227.9	0	0	0	0
Sweetwater County Total					233.9	820.3	374.1				
Uinta	-1106.98474	236.16992	Beacon #2 Extension	CT-4088	0	0	4.8	0	0	0	0
Uinta	-1086.35901	212.00684	Butcherknife Spring Unit 8	CT-2742	0	6.4	0	0	0	0	0
Uinta	-1164.23877	207.21045	Coyote Creek	CT-3003	0	44	0	5.39	422	12.5	0.41
Uinta	-1157.65833	230.61084	Evanston Facility	MD-881	0	1	0	0	0	0	0
Uinta	-1103.6438	193.41455	Luckey Ditch	wv-0517	0	5.5	0	0	0	0	0
Uinta	-1105.77637	195.58594	Luckey Ditch Unit G-9	wv-ED2	0	2.5	0	0	0	0	0
Uinta	-1155.56226	202.68457	Marvin Danielson Pit	CT-4144	0	3.4	1.6	0	0	0	0
Uinta	-1102.36096	224.04932	Oftedal FB1 Mine	CT-4189	0	0	1.7	0	0	0	0
Uinta	-1155.56226	202.68457	Pit 26	CT-3380	0	0	11.2	0	0	0	0
Uinta	-1104.51538	198.40186	Whiskey Springs 4	CT-3790	0	5.6	0	0	0	0	0
Uinta County Total					0	68.4	19.3				

Table B4.1.5: RFD Sources

EA/EIS	NOx (tpy)	SO2 (tpy)	PM10 (tpy)	PM2.5 (tpy)	VOC (tpy)	CO (tpy)
Hickey/Table Mountain	14.1	0.0	0.0	0.0	0.0	0.0
Road Hollow	88.0	55.0	0.9	0.9	0.0	0.0
Moxa Arch	3477.4	69.2	434.2	235.9	7058.6	4528.8
Atlantic Rim	657.8	63.7	1091.5	241.3	0.0	0.0
Greater Wamsutter	173.5	0.0	0.0	0.0	0.0	0.0
Creston Blue Gap	2.1	0.0	0.0	0.0	0.0	0.0
Desolation Flats	320.0	0.0	0.0	0.0	0.0	0.0
South Baggs	31.7	0.0	0.0	0.0	0.0	0.0
Black Butte Coal Pit	149.3	0.0	1074.9	0.0	0.0	0.0
Copper Ridge	193.1	0.0	0.0	0.0	0.0	0.0
Continental Divide	1.8	0.0	0.0	0.0	0.0	0.0
Roan Plateau	7.2	11.0	737.0	108.0	0.0	0.0
Vernal Field Office	10.2	5.0	122.5	18.0	0.0	0.0
Hiawatha	5675.0	68.0	298.0	198.0	13983.0	8653.0
Figure 4 Gap	494.1	11.1	438.6	91.2	0.0	0.0
Spaulding Peak	23.7	0.2	53.6	10.6	0.0	0.0
Gant Gulch Gap	206.8	3.4	164.6	34.5	0.0	0.0
Orchard Unit Gap	172.4	2.9	138.1	28.9	0.0	0.0
Grass Mesa Gap	368.8	5.9	205.4	28.5	0.0	0.0
Castle Springs GAP	218.4	3.4	146.7	31.8	0.0	0.0
Wheeler to Webster GAP	474.8	7.4	318.9	69.1	0.0	0.0
Rulison GAP	151.6	2.4	101.8	22.0	0.0	0.0
Pete and Bill Creek	93.6	1.5	62.9	13.6	0.0	0.0
EGL Resources Oil Shale	63.2	152.3	8.9	2.3	0.0	0.0
Alkali Creek Compressor Station	81.6	0.0	2.2	2.2	0.0	0.0

Table B4.1.6: State Permitted Wells; Colorado, Wyoming, and Utah

State[1]	County[2]	Total NO_x Emissions per County (tpy)	Percent of County within the Ashley Modeling Domain	Total NO_x Emissions Modele per County (tpy)
Colorado	Boulder	48.80	0.0%	0.00
	Garfield	1207.00	100.0%	1207.00
	Jackson	28.20	100.0%	28.20
	Larimer	33.00	0.0%	0.00
	Moffat	115.00	100.0%	115.00
	Rio Blanco	447.60	100.0%	447.60
	Routt	9.00	100.0%	9.00
			Total Emissions Modeled for Colorado Counties	1806.80
Utah	Carbon	86.50	100.0%	86.50
	Daggett	0.00	100.0%	0.00
	Duchesne	166.50	100.0%	166.50
	Emery	41.25	100.0%	41.25
	Garfield	-0.25	100.0%	0.00
	Grand	13.50	100.0%	13.50
	San Juan	-9.75	97.5%	0.00
	Sevier	2.50	100.0%	2.50
	Summit	-4.75	100.0%	0.00
	Uintah	642.50	100.0%	642.50
			Total Emissions Modeled for Utah Counties	952.75
Wyoming	Albany	-1.70	0.0%	0.00
	Carbon	77.10	56.2%	43.33
	Sweetwater	159.10	42.0%	66.82
	Unita	83.10	65.1%	54.10
			Total Emissions Modeled for Wyoming Counties	164.25
			Total Emissions Modeled for All Counties	2923.80

[1] Counties for each state shown only if they are within Ashley modeling domain

[2] Counties that are within the Domain but are not listed here did not have any wells listed for the years of interest

United States
Department of
Agriculture

Forest
Service

February 2012

Appendix D
Cultural Resources
Programmatic Agreement

South Unit Oil and Gas Development
Final Environmental Impact Statement

Duchesne Ranger District, Ashley National Forest
Duchesne County, Utah

PROGRAMMATIC AGREEMENT
AMONG
THE USDA FOREST SERVICE - ASHLEY NATIONAL FOREST,
THE BUREAU OF LAND MANAGEMENT - VERNAL FIELD OFFICE,
THE UTAH STATE HISTORIC PRESERVATION OFFICER,
THE ADVISORY COUNCIL ON HISTORIC PRESERVATION,
AND BERRY PETROLEUM COMPANY
REGARDING THE BERRY PETROLEUM
SOUTH UNIT OIL AND GAS MASTER DEVELOPMENT PLAN,
DUCHESNE COUNTY, UTAH
(Agreement # AS-11-00017)

WHEREAS, the Berry Petroleum Company (Berry) has proposed a Master Development Plan for oil and natural gas resources on leased lands within the South Unit of Ashley National Forest in Duchesne County, Utah; and,

WHEREAS, the Berry South Unit Oil and Gas Master Development Plan (Master Development Plan) includes the construction of well pads, roads, related facilities, and oil/natural gas wells across the Berry's lease area; and,

WHEREAS, the Ashley National Forest (Forest) Supervisor is the agency official as specified in 36 CFR 800.2(a) for approval of surface occupancy for leased lands within the South Unit of the Forest and has determined that the Master Development Plan is an undertaking as defined under 36 CFR 800.16(y); and,

WHEREAS, the Bureau of Land Management - Vernal Field Office Manager is the agency official for approval of the Application for Permit to Drill (APD) for Berry's lease area within the South Unit of the Forest as specified in 36 CFR 800.2(a); and,

WHEREAS, the Bureau of Land Management - Vernal Field Office (BLM) has designated the Forest as lead agency for the administration of this Programmatic Agreement (Agreement) for the Berry Development Plan; and,

WHEREAS, the Forest has consulted with the Utah State Historic Preservation Officer (SHPO) and other consulting parties on the Area of Potential Effects (APE) pursuant to 36 CFR 800.14(b); and,

WHEREAS, the Forest has consulted with the Advisory Council on Historic Preservation (Council) and the Council has elected to participate in the consultation process for this Agreement under 36 CFR Part 800.6 (a)(1); and

WHEREAS, the Forest has determined that the proposed Master Development Plan will have an adverse effect on properties included in or eligible for inclusion in the National Register of Historic Places (NRHP) and has consulted with the SHPO and Consulting Parties to create this

Agreement pursuant to 36 CFR Part 800.6 and 800.14(b) of the Council's regulations implementing Section 106 of the National Historic Preservation Act (NHPA), as amended [16 U.S.C. Section 470 (f)], as incorporated by reference herein; and

WHEREAS, the Berry Petroleum Company has legal responsibilities within this Agreement and has been invited to be a Signatory to this Agreement; and

WHEREAS, the Forest is responsible for government-to-government consultation with Federally recognized Indian Tribes for this undertaking and is the lead agency for all Native American consultation and coordination, and has formally invited the Ute Indian Tribe of the Uintah and Ouray Reservation, the Southern Ute Indian Tribe, the Mountain Ute Indian Tribe, and the Hopi Indian Tribe to participate in consultation regarding the potential effects of the project on historic properties to which they ascribe traditional religious and cultural significance; and

WHEREAS, the Ute Indian Tribe of the Uintah and Ouray Reservation (Ute Tribe) has participated in consultation and has been invited to be a Concurring Party to this Agreement; and

WHEREAS, the Utah Professional Archaeological Council (UPAC) has participated in consultation and has been invited to be a Concurring Party to this Agreement; and

WHEREAS, unless defined differently in this Agreement all terms are used in accordance with 36 CFR Part 800.16; and

NOW, THEREFORE, the Forest Service, BLM, Utah SHPO, and the Council agree that the undertaking shall be implemented in accordance with the following stipulations in order to take into account the effect of the undertaking on historic properties.

STIPULATIONS OF THIS AGREEMENT

1 Definitions of terms in this Agreement:

Agency Official **–** The official within an agency who has approval authority for the specific undertaking and who has the authority to commit or obligate the federal agency to an action.

Area of Potential Effect (APE) **–** The geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist. The APE is influenced by the scale and nature of an undertaking and may be different for different kinds of effects caused by the undertaking (36 CFR 800.16 (d)).

Concurring Party **–** A party who signs this Agreement, but is not legally or financially responsible for completion of stipulations. Concurring Parties may volunteer to assist with implementation of stipulations; however, they cannot terminate or amend the Agreement. For this Agreement, concurring parties include: the Ute Tribe and the Utah Professional Archaeological Council (UPAC).

***Consulting Party* –** Any party that has participated in the development of this agreement. This includes both Concurring Parties and Signatories.
***Cultural Resources* –** Any prehistoric or historic building, structure, feature, object, site, or district which is older than 50 years. The term includes artifacts, records, and materials that are related to and located in such properties.
***Cultural Resource (CR) Consultant* –** A qualified and Forest Service permitted professional consultant in cultural resources (archaeologist, historian, ethnographer, historic architect, architectural historian, or anthropologist) who is responsible for implementing cultural resource inventories and who prepares cultural resource documents, reports, analyses, records, and professional literature. The CR Consultant is funded by Berry and must meet the Secretary of the Interior's Professional Qualification Standards for Archaeology (36 CFR 61).
***Cultural Resource Inventory* –** A systematic and detailed field examination of an area to gather information about the number, location, condition, and distribution of cultural resources. Also referred to as a Class III survey, Class III Inventory, or intensive level survey. Cultural resource inventory typically requires a systematic pedestrian review of an area with transect intervals of 15 meters or less.
***Forest Archaeologist* –** The heritage professional designated by the Forest Supervisor to manage the Forest Heritage Program and implement this Agreement. The designated individual must meet core competencies of the position (FSM 2360.91) and meet the Secretary of the Interior's Professional Qualification Standards for archaeology (36 CFR 61).
***Historic Properties* –** Any prehistoric or historic district, site, building, structure, or object, and its associated artifacts, materials, features, setting, and records, that is either listed in or eligible for listing in the National Register of Historic Places (NRHP). All cultural resources are treated as "Historic Properties" until their National Register eligibility is determined (with SHPO concurrence).
***Master Development Plan* –** The proposal by Berry Petroleum to exercise their lease rights, and develop oil and gas resources within their existing federal oil and gas leases, located on the South Unit of the Ashley National Forest.
***Record of Decision* –** The Forest has developed an Environmental Impact Statement (EIS) to address environmental concerns of Berry's Master Development Plan. The Record of Decision for the EIS is the Forest's decision in regard to approving the nature and extent of actions outlined in Berry's Master Development Plan.
***Signatory* –** Parties who have legal or financial responsibilities in this Agreement. For this Agreement, signatories are the Forest, the BLM, the Utah SHPO, the Council, and Berry Petroleum Company.
***Site-Specific Project Area* –** Locations of site specific actions to be proposed under the Master Development Plan and the Environmental Impact Statement (i.e. individual well pads, roads, pipelines, etc.)
***Tribal Consultant* –** Native American Indian Tribe representative who has knowledge and experience with identifying Traditional Cultural Properties and other cultural resources to which Indian Tribes ascribe traditional religious and cultural significance.

2 Forest Responsibilities

The Forest Supervisor shall ensure that all actions required under this Agreement are fulfilled as specified herein before a Surface Use Plan is authorized or other activities are approved for each site-specific action under the Development Plan.

3 BLM Responsibilities

The BLM Field Office Manager will authorize an Application for Permit to Drill (APD) for wells submitted as part of the Master Development Plan only after the Forest has completed and submitted a signed “Cultural Resource Authorization to Proceed for the Application for Permit to Drill (APD)” (See Attachment A).

4 Berry Petroleum Company Responsibilities

Berry Petroleum Company (Berry) shall fund independent Cultural Resource (CR) Consultants to complete all cultural resources fieldwork, analysis, monitoring, data recovery, reporting, curation, and other mitigation required under this Agreement. CR Consultants will meet the Secretary of the Interior’s Professional Qualifications requirements. All reports, analyses, plans, or other products produced under this agreement, regardless of fund source, will be considered a Forest Service work product, owned by the Forest Service. CR Consultants will coordinate all work with the Forest Archaeologist.

Berry shall fund Tribal Consultants to identify Traditional Cultural Properties and Sacred Sites. Tribal Consultants will work closely with the CR Consultants and will coordinate all work with the Forest Archaeologist.

5 Consultation

The Forest Supervisor has identified and invited consulting parties pursuant to 36 CFR 800.2. The Forest has and will continue to consult with the Utah SHPO, the Council, the UPAC, the Ute Tribe, and Berry Petroleum on the fulfillment of stipulations associated with this Agreement.

The Forest Supervisor shall continue to consult with the appropriate Indian Tribes regarding historic properties of religious and cultural significance, in accordance with the NHPA, the Native American Graves Protection and Repatriation Act (NAGPRA), Archaeological Resources Protection Act of 1979 (ARPA), American Indian Religious Freedom Act of 1978 (AIRFA), Executive Order 13007 Sacred Sites, and their implementing regulations. The Forest Archaeologist will provide copies of any reports/studies developed pursuant to this Agreement to tribes expressing interest in consulting with the Forest during this project. See the Consultation Summary (Attachment B) for a full list of entities and organizations invited to consult on the project.

6 Standards and Qualifications

The Forest Archaeologist shall ensure that all work undertaken to satisfy the terms of this Agreement meets the “Secretary of the Interior’s Standards and Guidelines for Archeological and Historic Preservation” (48 FR 44716-44742, September 23, 1983)

(Secretary's Standards) and takes into consideration the Council's "Recommended Approach for Consultation on Recovery of Significant Information from Archaeological Sites", and "Guidelines for Evaluating and Documenting Traditional Cultural Properties", *National Register Bulletin 38*, 1989, as incorporated by reference herein. The Forest Archaeologist will also ensure that the work is carried out by or under the direct supervision of a person or persons meeting, at a minimum, the applicable professional qualifications standards set forth in the Secretary's Standards (36 CFR 61).

7 Inventory Procedures and Protocols

Berry Petroleum shall provide the Forest Archaeologist with the location and type of proposed activities under the Development Plan. The Forest Archaeologist will coordinate with the CR Consultant and Tribal Consultant and shall ensure implementation of the Preconstruction Cultural Resource Plan (Preconstruction Plan, Attachment C) for all site-specific actions prior to approval of the action. The Preconstruction Plan outlines the procedures for inventory, identification, evaluation, documentation, avoidance, and mitigation of cultural resources within the site-specific project area.

8 Resolution of Adverse Effects

The Forest Supervisor has applied the criteria of adverse effects for the project as required by 36 CFR 800.5 and has determined that the project as proposed in the Master Development Plan will have an adverse effect on Historic Properties. The Forest has consulted with the SHPO and other consulting parties to seek ways to avoid, minimize, or mitigate the adverse effects as required by 36 CFR 800.6. The following is an outline of the process for resolution of effects.

Berry (assisted by the CR Consultant) shall follow the Standard Avoidance Protocols as described in the Preconstruction Plan (Attachment C) to avoid adverse effects to Historic Properties whenever possible. Avoidance procedures may include, but are not limited to, rerouting pipelines, rerouting road corridors, moving well pad locations, or moving other facilities.

When Berry is unable to modify the location of a facility or activity to meet standard avoidance protocols, the CR Consultant, under the direction of the Forest Archaeologist and in consultation with consulting parties, shall develop a plan to minimize or mitigate the adverse effects of the specific facility or activity (see the Preconstruction Plan, Attachment C).

9 Authorization of Site Specific Actions

When the Forest Archaeologist determines that a site specific action will avoid adverse effects to Historic Properties by meeting the Standard Avoidance Protocols and requirements of the Preconstruction Plan, the Forest Supervisor may authorize the action immediately upon completion of the appropriate documentation specified in the Preconstruction Plan. The documentation will be submitted to the SHPO for archival purposes. The documentation will be submitted to other consulting parties as requested.

When a site specific action cannot avoid adverse effects to Historic Properties by meeting the Standard Avoidance Protocols of the Preconstruction Plan, the CR Consultant, under the direction of the Forest Archaeologist shall develop a plan to minimize or mitigate the potential adverse effects (See Preconstruction Plan – Attachment C). The plan at a minimum will specify desired results, required processes, required documentation, required analysis, and the procedures and timeframe for authorizing the action. The Forest Archaeologist will provide the plan to consulting parties for review. After the signatories have agreed to the plan and signed a letter agreement, the CR Consultant will implement the plan. Upon completion of the plan requirements and the resolution of adverse effects, the Forest Supervisor may authorize the specific action.

10 Program Activities Exempt From Further Review

The Forest Supervisor may authorize the following actions in areas that have been previously inventoried and reviewed, if the Forest Archaeologist determines that the previous inventory meets current standards and the action will avoid Historic Properties according to Standard Avoidance Protocols:

a. the drilling of additional wells on an existing well pad.

b. the installation of additional facilities, such as storage tanks and pumping structures, on an existing well pad.

c. the replacement and repair of existing pipelines and the addition of new pipelines within an existing corridor.

d. the repair, maintenance, and minor expansion of existing roads.

e. the repair, maintenance, and minor expansion of existing well pads or facilities.

f. The survey, staking, and mapping of proposed well pad locations by engineers prior to cultural resource inventory of the area. Limited and temporary placement of staking lath within areas potentially containing Historic Properties will not cause an adverse effect. Off-road motorized vehicle access is <u>not</u> authorized for this activity.

11 Monitoring Plan

The CR Consultant, under the direction of the Forest Archaeologist, shall prepare a Cultural Resources Monitoring Plan for the project in order to determine if project activities are causing indirect or cumulative effects to cultural resource sites in the broader project area. The Monitoring Plan shall be developed within one year of the approval of this Agreement and shall be implemented by the CR Consultant, under the direction of the Forest Archaeologist, throughout the life of this Agreement. The Monitoring Plan requirements are outlined in Attachment D.

12 Collections

During archaeological surveys within the project area, the collection of artifacts will be limited to specific artifacts types as described in the Ashley National Forest Guidelines for Cultural Resource Inventory and Site Documentation (Attachment E).

During data recovery or mitigation activities, artifact collection will follow the guidance of an approved mitigation plan in consultation with the Ute Indian Tribe.

The CR Consultant, under the direction of the Forest Archaeologist, shall ensure that artifacts collected during the project are curated and documented in accordance with 36 CFR 79. Collections that may be repatriated in accordance with the provisions of the NAGPRA and applicable state laws (i.e., Utah 9-9-401 to 406) (i.e., human remains, associated and unassociated funerary objects, sacred objects, and objects of cultural patrimony) will be curated in accordance with 36 CFR 79 until they have been repatriated. All costs of curation, which typically include proper documentation, transfer of materials, and long-term storage of artifacts, photographs, archaeological site forms, and reports at an accredited repository, will be borne by Berry.

13 Personnel Training

All Berry personnel (including contractors; new, added, or replaced Berry employees; etc.) involved in construction, operation, and maintenance activities associated with the Berry Full Field Development Project shall be instructed (to a degree appropriate to their involvement in the Project) by Berry, with Forest Archaeologist oversight, on cultural resource site avoidance and protection measures. The instruction will be required prior to being authorized to work in the Project Area and will be a part of Berry's internal training program. At a minimum, all employees shall receive written information sheet(s) that discuss the importance of cultural resources and laws pertaining to their protection, including penalties for violation (Attachment F).

Personnel who routinely work in the project area shall be required to receive additional cultural resource awareness training that will be developed by Berry with Forest Archaeologist oversight and in consultation with the Ute Tribe.

Berry shall maintain records demonstrating that the above described personnel training has been carried out. Signatories and Concurring Parties of this Agreement may participate in development of this training program.

14 Post-Review Discoveries

If cultural resources are discovered or affected after Berry has been authorized to proceed with an action, the Forest and Berry shall implement the Cultural Resource Inadvertent Discovery Plan (Attachment G).

15 Emergency Situations

In the event of an emergency response to a disaster or event that is an immediate threat to life or property, the Forest Archaeologist will follow the regulations outlined in 36 CFR 800.12.

16 Dispute Resolution

Should any Concurring Party or Signatory object, in writing, at any time to any actions proposed or the manner in which the terms of this Agreement are implemented, the Forest shall consult with the objecting party to resolve the concern within 45 days. If the Forest Archaeologist determines that the concern cannot be resolved, the Forest shall forward all documentation relevant to the dispute, including the Forest's proposed resolution, to the Council. The Council shall provide the Forest with its advice on the resolution of the concern within 30 days of receiving adequate documentation. Prior to reaching a final decision on the dispute, the Forest shall prepare a written response that takes into account any timely advice or comments regarding the dispute from the Council, Signatories, and Concurring Parties, and provide them with a copy of this written response. The Forest Supervisor will then proceed according to its final decision. If the Council does not provide its advice regarding the dispute within the 30 days time period, the Forest may make a final decision on the dispute and proceed accordingly.

Prior to reaching such a final decision, the Forest Archaeologist shall prepare a written response that takes into account any timely comments regarding the dispute from the Signatories and Concurring Parties to this Agreement, and provide them and the Council with a copy of such written response.

The Forest's responsibility to carry out all other actions subject to the terms of this Agreement that are not the subject of the dispute will remain unchanged.

17 Protection of Confidential Information

Each Signatory and Concurring Party to this Agreement shall safeguard information about the nature and location of archaeological, historic, and Traditional Cultural Properties, pursuant to Section 304 of the NHPA and Section 9 of the ARPA.

The Forest Archaeologist shall ensure that all confidential information, as defined in Section 9 of the ARPA and Section 304 of the NHPA is managed in such a way that historic properties, archaeological resources, traditional cultural values, and sacred objects are not compromised, to the fullest extent available under law.

18 Amendments

Any Signatory or Concurring Party to this Agreement may request that it be amended, whereupon the Signatories will consult to consider such amendment. An amendment will go into effect upon written agreement by all Signatories.

The attachments to this Agreement may be amended or modified by the Forest upon written agreement by designated representatives of each Concurring Party.

19 Termination

Any Signatory to this Agreement may terminate it by providing 30 calendar days notice, in writing, to the other Signatories, provided that the Signatories will consult during the period prior to termination to seek agreement on amendments or other actions that will avoid termination. In the event of a termination, the Forest, Berry and other Signatories shall comply with 36 CFR Part 800.3 through 800.7 with regard to individual actions covered by this Agreement. Any Concurring Party to this agreement may withdraw their concurrence and participation at any time by written notice, but such withdrawal will not terminate this Agreement or affect it in any way.

20 Term

This Agreement shall be effective when all Signatories have signed it and will automatically terminate on the tenth anniversary thereof, unless each of the Signatories agrees to extend the term hereof through an amendment per Stipulation 13. All Signatories and Concurring Parties will meet prior to the termination date to discuss extending the term.

21 Annual Review

The CR Consultant and the Forest Archaeologist will prepare a brief annual report summarizing the review and authorization of site-specific activities during the year and will submit the report to the Signatories and Concurring Parties (See Preconstruction Plan, Attachment C). The Forest, SHPO, and consulting parties will meet annually to review the functionality and effectiveness of the Programmatic Agreement. The annual meeting may be held as a tele-conference call if all parties agree.

22 Anti-Deficiency Act

The stipulations of this Agreement are subject to the provisions of the Anti-Deficiency Act (31 U.S.C. Section 1341) and availability of funds. If compliance with the Anti-Deficiency Act alters or impairs the ability of the Forest to implement stipulations of this Agreement, the Forest shall consult with the SHPO regarding the matter and acceptable alternatives. The responsibility of the Forest to carry out all other obligations that are not subject of the deficiency will remain unchanged.

Execution of this Programmatic Agreement by the Forest Service, BLM, Utah SHPO, and the Council and implementation of its terms evidence that the Forest Service and BLM have taken into account the effects of this undertaking on historic properties and afforded the Council an opportunity to comment.

SIGNATORIES FOR THE BERRY PETROLEUM COMPANY MASTER DEVELOPMENT PLAN PROGRAMMATIC AGREEMENT

U.S. Forest Service, Ashley National Forest
Kevin B. Elliott
Ashley National Forest Supervisor

By:________________________ Date: 6 SEP 2011

Bureau of Land Management, Vernal Field Office
Michael Stiewig
Vernal Field Office Manager

By:________________________ Date: 9/15/11

Utah State Historic Preservation Officer
Wilson Martin

By:________________________ Date: 9/22/11

Advisory Council on Historic Preservation
John M. Fowler
Executive Director

By: John M. Fowler Date: 10/14/11

Berry Petroleum Company, Inc.
Wayne King
Uinta Asset Manager

By: Wayne King Date: 9/12/11

CONCURRING PARTIES FOR THE BERRY PETROLEUM COMPANY MASTER DEVELOPMENT PLAN PROGRAMMATIC AGREEMENT

Ute Indian Tribe of the Uintah and Ouray Reservation
Tribal Chairman

By:____________________ Date:________________

Utah Professional Archaeological Council
James Allison
President

By: [signature] Date: 9/19/2011

Attachment A

Cultural Resource Authorization to Proceed for the Application for Permit to Drill (APD)

Ashley National Forest
U.S Forest Service
Cultural Resource Authorization to Proceed
for the Application for Permit to Drill (APD)

Well Number:	
Well Operator:	
Other Wells on the same pad:	
Proposed Well Pad Size (in acres):	

The proposed well pad location, access routes, pipelines, and facilities as described in the APD are actions that have been reviewed under the Programmatic Agreement prepared for the Berry Petroleum South Unit Oil and Gas Master Development Plan (Agreement # AS-11-00017).

Requirements of the Preconstruction Cultural Resource Plan (Attachment C of the Programmatic Agreement) have been completed and adverse effects have been avoided, minimized, or mitigated in compliance with the Programmatic Agreement and 36 CFR 800 regulations. The documents required under the Programmatic Agreement are summarized below and are on file with the Ashley National Forest Heritage Program in Vernal, Utah.

Ashley Heritage Project # :	
Utah State History Project #:	
Field Work Completed by:	
Field Supervisor / Author:	
Date of Report:	
Date Report Sent to SHPO / or Concurrence Date:	
Tribal Consultation:	

Ashley National Forest, as the lead federal agency for the action, has complied with Section 106 of the National Historic Preservation Act and its implementing regulations (36 CFR 800) by fulfilling requirements of the Berry Petroleum South Unit Oil and Gas Master Development Plan Programmatic Agreement (AS-11-00017). The activities described in the APD are authorized to proceed, with the following stipulations added as Conditions of Approval (COA) for the APD.

Stipulations:
1. The proposed project area has been surveyed for archaeological resources and none were found. However, if construction activities uncover or expose buried archaeological resources, the applicant and subcontractors will cease all activities within 100ft/30m of the discovery. The applicant will contact Ashley National Forest and will follow the Cultural Resource Inadvertent Discovery Plan (Attachment G of the Programmatic Agreement).
2. All personnel involved in construction, operation, and maintenance of the facilities described in the APD will sign and follow the "Archaeological Rules and Restrictions for Berry Petroleum Oil and Gas Development on Ashley National Forest Lands" (Attachment F of the Programmatic Agreement).
3.

Certified by the Ashley National Forest Archaeologist		
Printed Name	Signature	Date

Attachment B

Consultation Summary

Consultation Summary

Organizations consulted during development of the Programmatic Agreement

Date	Consulted Organization	Nature of Consultation	Results of Consultation
1/21/2009	Deputy State Historic Preservation Officer (SHPO), Lori Hunsaker	Met to discuss the project and Section 106 process.	Began development of Programmatic Agreement (PA)
3/25/2009	Ute Tribe of the Uintah and Ouray Reservation, Betsy Chapoose	Met to discuss the project and invited the tribe to participate.	Ute Tribe agrees to participate.
4/30/2009	Colorado Plateau Archaeological Alliance, Jerry Spangler	Sent letter to invite for consultation.	No response
4/30/2009	Hopi Tribe, Benjamin Nuvamsa	Sent letter to invite for consultation.	No response
4/30/2009	Southern Utah Wilderness Alliance	Sent letter to invite for consultation.	No response
4/30/2009	Southern Ute Indian Tribe, Matthew Box	Sent letter to invite for consultation.	No response
4/30/2009	Utah Professional Archaeological Council, Elizabeth Skinner	Sent letter to invite for consultation.	UPAC agrees to participate
4/30/2009	Utah Rock Art Research Association, Steve Robinson	Sent letter to invite for consultation.	Declined to participate
11/23/2010	Advisory Council on Historic Preservation, Katry Harris	Sent letter to invite for consultation.	Council agrees to participate
12/14/2010	Ute Mountain Tribe, Terry Knight	Sent letter to invite for consultation.	No response

Attachment C

Preconstruction Cultural Resource Plan

PRECONSTRUCTION CULTURAL RESOURCE PLAN

The Ashley National Forest and consulting parties have evaluated the potential effects of the South Unit Oil and Gas Full Field Development Project on Historic Properties through the development of a Programmatic Agreement. Because the Project and the Programmatic Agreement are conceptual in nature, this Preconstruction Cultural Resource Plan outlines the procedures for the identification, evaluation, management, monitoring, and mitigation (if necessary) of cultural resources for site-specific actions within the South Unit Project Area under the Programmatic Agreement.

The Area of Potential Effect (APE) for individual site-specific actions, such as well pads, access roads, pipelines, and other surface facilities will require site-specific types of identification, monitoring, evaluation, or mitigation of cultural resources. Indirect and cumulative effects are evaluated at the overall project level and are managed or evaluated through the Monitoring Plan.

Berry Petroleum Company shall fund all cultural resources fieldwork, analysis, monitoring, data recovery, reporting, curation, mitigation, and other mandates required under the Programmatic Agreement.

All cultural resource work required under the Programmatic Agreement will be completed by Cultural Resource (CR) Consultants who meet the Secretary of the Interior’s Professional Qualification Standards and by Tribal Consultants who have the knowledge and ability to identify Traditional Cultural Properties and Sacred Sites.

CULTURAL RESOURCE CONSULTANTS AND TRIBAL CONSULTANTS

The CR Consultant will coordinate closely with the Forest Archaeologist to ensure identification efforts and documentation meet necessary standards. The Forest Archaeologist will make the final determination concerning the contents and sufficiency of the CR Consultant's work and report.

In order to avoid a potential conflict of interest between Berry and the CR Consultant, the Forest will be involved in the selection process for the CR Consultant. Berry will select a Cultural Resource (CR) Consultant with field supervisors who meet the Secretary of the Interior’s Professional Qualification Standards and who are Registered Professional Archaeologists. Selection will be based on the consultant’s demonstrated ability to complete accurate surveys, submit professional reports, respond in a timely manner to work requirements, and prepare and execute mitigation plans. The Forest Archaeologist may require that Berry select a different CR Consultant if the quality of work from the existing CR Consultant becomes unacceptable.

The Ute Tribe will select Tribal Consultants to identify Traditional Cultural Properties and Sacred Sites within the Area of Potential Effect. The Tribal Consultants will be funded by Berry and will work closely with the CR Consultant and the Forest Archaeologist to provide information on Traditional Cultural Properties and Sacred Sites.

Prior to conducting the field inventory, the CR Consultant will obtain a cultural resource fieldwork authorization permit from Ashley National Forest (Forest).

The CR Consultant shall safeguard information about the nature and location of archaeological sites, Historic Properties, Traditional Cultural Properties, and Sacred Sites pursuant to Section 304 of the NHPA and Section 9 of the ARPA. Reports, site forms, maps, and other documents containing site-specific cultural resource information will be regarded as sensitive information and will not be disclosed without written authorization from the Forest Archaeologist.

INVENTORY

Berry will provide the locations of proposed well pads, roads, pipelines, and other facilities to the CR Consultant and to the Forest Archaeologist as they are considered under the Development Plan. The CR Consultant will identify and document cultural resources within proposed specific development areas in accordance with the Ashley National Forest Guidelines for Cultural Resource Inventory and Site Documentation (Attachment E).

If an area within an individual APE has been previously inventoried and the Forest Archaeologists determines the existing inventory is adequate, no new survey will be required in the area. If unevaluated or poorly documented cultural resources occur in a previously inventoried area, the CR Consultant will investigate and document the cultural resources in a similar manner to newly recorded cultural resource sites.

Tribal Consultants will conduct field identification in areas of proposed development as appropriate and will provide information on Traditional Cultural Properties and Sacred Sites to the Forest Archaeologist or to the CR Consultant for inclusion in the reports submitted to the Forest Archaeologist.

Cultural resource identification requirements will be based on the minimum survey requirements described below and in Table 1. Additional inventory may be required for some types of cultural resources.

Minimum Cultural Resource Survey Requirements

1. Well pads: Survey of a 40 acre block, surrounding the staked drill location (center stake). This survey area would typically be large enough to allow for some movement or expansion of the well pad location without having to complete additional survey.
2. New roads: Survey of a 300 foot wide corridor (150 feet on either side of the road centerline). This corridor width allows for placement of pipelines and drainage features along the road edge.
3. Minor road upgrades (includes culverts, drainage ditches, etc) and placement of surface pipelines along existing roads: Survey of a 100 foot buffer on each side of the road. This survey area allows for repairs, drainage features, and pipelines along the edge of the road.
4. Surface pipelines away from roads. Survey of a 200 foot wide corridor (100 feet on either side of the pipeline centerline). This survey width allows room for vehicles to install and access the pipeline.

5. Buried pipelines. Survey of a 400 foot wide corridor (200 feet on either side of the pipeline centerline). This corridor width allows for movement of heavy machinery along the route.
6. Other facilities (I.E. compressor stations, tank batteries, etc.): Survey of the facility disturbance footprint plus a 300 foot buffer on all sides. This survey area would typically be large enough to allow for some movement or expansion of the facility location without having to complete additional survey.

Table 1. Summary of Minimum Cultural Resource Survey Requirements

Activity Type	Survey Requirements	Reason for Requirements
Well pad	40 Acre survey for well pads	Allows room to move or expand the well pad location
Roads	300 foot corridor (150 feet on either side of center line)	Allows room for repairs, pipelines, and drainage features along the road edge (Standard with BLM)
Minor road upgrades and pipelines along road.	At least 100 foot buffer on each side of the road.	Provides sufficient survey for activities along the road edge (Standard with BLM)
Surface pipeline away from roads	200 foot corridor (100 feet on either side of center line)	Allows room for vehicles to install and access pipeline (Standard with BLM)
Buried pipeline	400 foot corridor (200 feet on either side of center line)	Allows room for the movement of heavy equipment
Other facilities	Facility Footprint plus 300 foot buffer	Allows room to move or expand the facility

EVALUATION

The CR Consultant will apply National Register criteria for all cultural resource sites identified within a specific project area and will provide the Forest Archaeologist with a recommendation of National Register eligibility for each site. Guidance for applying the National Register criteria is found in National Register Bulletins and other guidance by the National Register Program administered by the National Park Service within the Department of Interior. The National Register criteria for evaluation are found in 36 CFR 60 and are included below:

The quality of significance in American history, architecture, archaeology, and culture is present in districts, sites, buildings, structures, and objects of State and local importance that possess integrity of location, design, setting, material, workmanship, feeling and association, and:
A) That are associated with events that have made a significant contribution to the broad patterns of our history; or
B) That are associated with the lives of persons significant to our past; or

C) That embody the distinctive characteristics of a type, period, or method of construction, or that represent the work of a master, or that possess high artistic value, or that represent a significant and distinguishable entity whose components may lack individual distinction; or
D) That have yielded or may be likely to yield information important in prehistory or history.

Cultural resource districts, sites, buildings, structures, and objects that meet National Register criteria are “Historic Properties” as defined by 36 CFR 800.

Some cultural resource sites will require subsurface testing to determine if they meet the requirements of Criterion D. In such cases the CR Consultant, under the direction of the Forest Archaeologist, will develop and implement a site testing plan to determine if sites may be likely to yield information important in prehistory.

The Forest Archaeologist will make a determination of eligibility after reviewing the site documentation and National Register recommendation prepared by the CR Consultant. The Forest Archaeologist will consult with the SHPO and Ute Tribe on National Register eligibility determinations before authorizing actions which may affect the Historic Properties.

STANDARD AVOIDANCE PROTOCOL

It is the policy of the Forest that adverse effects to Historic Properties be avoided whenever possible. If avoidance is not possible or feasible, then the Forest Archaeologist can develop ways to minimize or mitigate the adverse effects.

If National Register-eligible cultural resource sites are found within the proposed development area, the CR Consultant will recommend ways in which Berry can avoid effects to the Historic Properties without divulging the location or character of the cultural resources. Recommendations by the CR Consultant can include, but are not limited to, rerouting pipelines, rerouting road corridors, moving well pad locations, or moving facilities.

In order for activities to completely avoid adverse effects to National Register-eligible cultural resources under these Standard Avoidance Protocols, the following avoidance buffers must be achieved. Avoidance protocols are also summarized in Table 2.

1. Well pads and other facilities: The outer edge of the well pad or facility footprint must be at least 150 feet from any Historic Property. The 150 foot buffer increases the ability to expand or modify the well pad or facility location in the future.
2. New roads and road reroutes: The outer edge of the road footprint must be at least 100 feet from any Historic Properties. This avoidance buffer allows for the placement of pipelines and drainage features along the edge of the road.
3. Road upgrades (culverts, widening, etc.): The outer edge of the road footprint must be at least 100 feet from any Historic Property. This avoidance buffer allows for the placement of pipelines and drainage features along the edge of the road.

4. Surface pipelines away from roads: The pipeline footprint must be at least 100 feet from any Historic Property. This avoidance buffer allows room for vehicles to install and access the pipeline.
5. Buried pipelines: The pipeline must be at least 200 feet away from any Historic Property. This avoidance buffer allows room for heavy equipment to excavate and move along the pipeline.

Table 2. Summary of Standard Avoidance Protocols

Activity or Facility	**Forest Avoidance Requirements**	**FS Reasons for Avoidance Requirements**
Well pad and other facilities	150 feet from edge of disturbance	Increases the ability to expand or modify the well pad or facility location.
New roads and road reroutes	100 feet from edge of disturbance	Allows room for repairs, pipelines, and drainage features along the road edge (Standard with BLM)
Road upgrade (culverts, widening, etc.)	100 feet from edge of disturbance	Allows room for repairs, pipelines, and drainage features along the road edge (Standard with BLM)
Surface pipeline away from roads	100 feet from pipeline	Allows room for vehicles to install and access pipeline (Standard with BLM)
Buried pipeline	200 feet from pipeline	Allows room for the movement of heavy equipment

The Forest will consult with the Ute Tribe and other consulting parties for specific avoidance needs when human burials, Traditional Cultural Properties, or Sacred Sites are identified within the project area.

DECISION TO MINIMIZE OR MITIGATE ADVERSE EFFECTS

When the Forest Archaeologist determines that the adverse effects of a proposed development on a Historic Property cannot be avoided with standard avoidance protocols, the CR Consultant, under the direction of the Forest Archaeologist and in consultation with the consulting parties, will develop a plan to minimize or mitigate the adverse effects of the action.

The Forest Archaeologist will submit the draft plan to the consulting parties for review and consulting parties will have 30 days to comment on the draft. The plan at a minimum will specify the process to minimize or mitigate adverse effects, the desired results, the required processes, the required documentation, the required analysis, and the procedures and timeframe for authorizing the action. The Forest Archaeologists and the CR Consultant will address the comments from the consulting parties and prepare a final plan. If comments are substantive or if a consulting party disagrees with the plan, the Forest may organize a meeting (in person or through tele-conference) with the concerned consulting parties to come to an agreement. After any concerns have been resolved, the CR Consultant, under the direction of the Forest Archaeologist, will prepare a final plan to minimize or mitigate the adverse effects. The Forest Archaeologist will draft a letter agreement for the plan and submit the documents to the Signatories of the PA (or their authorized representatives) for signature. After signature of the letter agreement for the plan, the CR Consultant will implement the plan.

All mitigation efforts will have a public education or public outreach component. Public education may include a variety of formats, including websites, publications, professional articles, signs, or other methods for providing archaeological and historical information to the public.

AUTHORIZATION OF SITE-SPECIFIC ACTIONS

When a site specific action will comply with the Standard Avoidance Protocols and the CR Consultant has completed the requirements of the Preconstruction Plan, the Forest Supervisor may authorize the action immediately upon completion of the appropriate documentation specified in the Preconstruction Plan. The Forest Archaeologist will subsequently prepare and sign a "Cultural Resource Authorization to Proceed for the Application for Permit to Drill (APD)." The documentation will be submitted to the SHPO for reference purposes.

When a site-specific action cannot comply with the Standard Avoidance Protocols, the CR Consultant, under the direction of the Forest Archaeologist and in consultation with the consulting parties, shall develop a plan to minimize or mitigate the potential adverse effects. Upon completion of the plan requirements and the acceptance by the Forest and the Consulting Parties of the resolution of the adverse effects, the Forest Supervisor may authorize the specific action. The Forest Archaeologist will subsequently prepare and sign a "Cultural Resource Authorization to Proceed for the Application for Permit to Drill (APD)."

DOCUMENTATION AND REPORT REQUIREMENTS

Cultural resource inventory reports will adhere to the requirements specified in the Ashley National Forest *Guidelines for Cultural Resource Inventory and Site Documentation* (Attachment E) and the *Secretary of the Interior's Standards and Guidelines for Archaeological and Historic Preservation*. As such, the reports will include a description of previous work in the vicinity of the undertaking, a cultural history overview, a summary of the findings of the inventory, completed cultural resource site forms, eligibility recommendations, and management recommendations.

Annual Report

The CR Consultant and the Forest Archaeologist will prepare a brief annual report summarizing the review and authorization of site-specific activities during the calendar year. The annual report will be provided to the consulting parties before the annual meeting to review the Programmatic Agreement. The annual report, at a minimum, will include:

1. A list of well pads, facilities, roads, and pipelines authorized during the calendar year.
2. A list of cultural sites documented during the calendar year.
3. A list or bibliography of reports submitted during the calendar year.
4. A brief discussion of mitigation plans developed or signed during the calendar year.
5. Acreage of survey completed during the calendar year.
6. A brief discussion of issues, problems, or successes during the calendar year.

Attachment D

Cultural Resource Monitoring Plan

CULTURAL RESOURCE MONITORING PLAN

The Cultural Resource Monitoring Plan serves to monitor two types of potential inadvertent adverse effects within the Master Development Plan area.

First, the monitoring plan will help the Forest to assess and evaluate indirect and cumulative effects of the South Unit Oil and Gas Master Development Plan over time. Indirect effects to Historic Properties are often a result of unanticipated activities or actions that were not foreseeable during initial project planning. Cumulative effects to Historic Properties are often a result of repeated minor activities that may not individually constitute an adverse effect, but when combined, may result in an adverse effect.

Second, the monitoring plan will help the Forest avoid inadvertent adverse effects to buried cultural sites in areas of construction and excavation activities. Excavation and construction activities can inadvertently affect buried Historic Properties that were not found during identification efforts because the sites were not visible on the ground surface.

The Forest Archaeologist will ensure implementation of the Cultural Resources Monitoring Plan. Berry will fund the Cultural Resource (CR) Consultant to prepare and implement the Monitoring Plan, including site visitation, documentation, monitoring, testing, evaluation, and review.

Indirect and Cumulative Effects Monitoring Plan

Under the direction of the Forest Archaeologist, the CR Consultant will select a variety of Historic Properties to monitor for indirect and cumulative effects within the Master Development Plan area.

<u>Site Selection</u>

The Monitoring Plan will include a selection of Historic Properties within the Master Development Plan area that have a high risk for adverse effects because they meet the following criteria:

1. Historic Properties near approved actions and developments.

   This category includes Historic Properties that are located relatively close to site specific project areas (within 300 ft/100m of well pads, roads, or facilities) or located in geological settings near site-specific project areas that may encourage visitation (e.g. ridge tops, cliffs, or outcrops near well pads, roads, or facilities).

2. Historic Properties with known or ongoing impacts.

   This category includes Historic Properties that are known to have been impacted by visitation or previous project activities.

3. Historic Properties with known visibility.

   This category includes Historic Properties that are frequently visited because of specific attributes that draw the public, such as rock art sites, sites with structures, rock shelters, or caves.

4. Historic Properties with exceptionally significant integrity or data potential.

   This category includes Historic Properties that have provided or may provide extremely significant data regarding the prehistory of the area.

Monitoring Process

Historic Properties selected for monitoring will be thoroughly documented during an initial baseline review that will include an inspection of the cultural resource site area, a site condition assessment, site photographs, and data entry of the site condition into the Forest site monitoring database. The baseline documentation will be completed before nearby site specific actions are authorized. The Historic Properties included in the monitoring plan will be revisited within one year from the date that nearby site-specific construction is completed. The Historic Properties will then be revisited at least once every five years during the life of the project. Historic Properties may be revisited on an annual basis if monitoring indicates any type of effect to the site. Historic Properties may be removed from the Monitoring Plan if no effects are documented after four sequential visits. Additional sites may be added to the Monitoring Plan if the Forest Archaeologist determines they have a high risk of adverse effects from project activities. Each site revisit will include documentation of any changes or effects to the site.

The Forest Archaeologist will use information from monitoring assessments to determine if any effects to the site could be considered adverse effects and to determine if the effects are caused by activities associated with the implementation of the Master Development Plan.

If the Forest Archaeologist determines that sites are being adversely affected by activities or individuals associated with the Master Development Plan, s/he will provide information to the consulting parties regarding the effects and will consult to resolve the adverse effects. The CR Consultant, under the direction of the Forest Archaeologist, will develop a plan to minimize or mitigate the adverse effects using similar processes as outlined in the Preconstruction Plan (Appendix C).

Excavation and Construction Monitor Plan

Under the direction of the Forest Archaeologist, the CR Consultant will monitor excavation and ground disturbing activities that may adversely affect unidentified buried Historic Properties.

The CR Consultant shall monitor excavation or construction activities when they occur in the following locations:

1. Construction or excavation within non-eligible prehistoric sites. This is necessary to ensure that the site does not contain subsurface features which could make it eligible for the National Register.
2. Construction or excavation in areas with deep alluvial deposits that are near Historic Properties. This is necessary to ensure that buried Historic Properties that may not be visible on the ground surface are not adversely affected.
3. Construction or excavation in areas with limited ground visibility near Historic Properties in order to ensure that buried Historic Properties are not within the project area.
4. When specified by a Mitigation Plan.

When cultural resources are encountered during construction or excavation, Berry and the CR consultant will follow the procedures of the Inadvertent Discovery Plan in Attachment G.

Attachment E

Ashley National Forest
Guidelines for Cultural Resource Inventory and Site Documentation

Ashley National Forest Guidelines for
Cultural Resource Inventory and Site Documentation

Version 6/27/2011

Cultural Resource Contractors and Forest Staff will complete cultural resource inventory and cultural resource documentation through the following procedures:

I. Pre-Field Work

A. Forest ARPA Permit
   1) Cultural Resource Contractors must obtain a Forest ARPA permit prior to initiating any work on the Forest.

B. File Search.
   1) Complete a file search at the Ashley National Forest Heritage Office
      a) Review Heritage GIS database and site files for previous projects and previously recorded cultural resources located within 500m of the current project area.
      b) Review Utah State History maps and site files for previous projects and previously recorded sites located within 500m of the current project area.
      c) Review any available historic maps of the project area, including General Land Office (GLO) maps.
      d) Review the Forest historic special use permit database for the project area.
      e) Based on previous data, determine if new inventory is required and which existing sites will need to be revisited.

C. Heritage Project and Site Numbers.
   1) Obtain a Forest Project number from Ashley National Forest Heritage Program before beginning fieldwork.
   2) Obtain a State History Antiquities Section project number for the project.
      a) All digital data, reports, and site forms must have Forest numbers as well as state numbers before they are submitted for review.

D. Professional qualification requirements
   1) All cultural resource fieldwork, documentation, and evaluation must be completed by or directly supervised by an individual who meets the Secretary of the Interior's Qualification Standards.

II. Identification Standards

A. Cultural resource contractors and Forest staff are to use the following protocol for field survey and inventory:
   1) All survey will be intensive-level pedestrian survey at 15m intervals or less.
   2) The survey requirements for all proposed locations will be coordinated with the Forest Archaeologist who will determine the extent of the Area of Potential Effect.
      a) Inventory efforts will determined based on the following factors:
         (1) Nature and scope of the project
         (2) Site potential for the project area
         (3) Magnitude of the project
         (4) Potential for indirect and cumulative effects

(5) Minimum inventory efforts will not be less than the project footprint plus a 30m (100ft) buffer on each side.

b) Specific project types may require additional survey based on project needs and the potential for changes in location.

c) The Forest archaeologist may use professional judgment to reduce survey requirements in areas where terrain, vegetation, or safety hazards warrant a change from the standards.

III. Documentation Standards

A. All sites will be documented with sufficient information to understand intra-spatial organization of the site and to enable relocation of all site components.

1) All features, tools, concentrations, or unique artifacts will be mapped with professional grade GPS units.
2) GIS data collection will follow standards outlined in Section V.
3) All sites in Utah will be documented with fully completed IMACS site forms. All sites in Wyoming will be documented with fully completed Wyoming Cultural Resource Forms.
4) All site documentation will include:
   a) Specific descriptions and measurements of all formal tools, groundstone, features, and structures.
   b) Detailed and accurate site plan sketch (using GIS data) showing locations of formal tools, groundstone, features, structures, and geographic/topographic references (contours, roads, fences, waterways, etc.). Sketch maps will include labeled UTM grid tics along map edges.
   c) Photographs of all prehistoric formal tools, diagnostic artifacts, site features, and structures (include scale reference in photos).
   d) Photographs of historic features and structures (include scale reference in photos)
   e) At least two site overview photographs. More site overview photographs should be taken for large or complex sites.
   f) Placement of a permanent site datum which includes date of placement and site number. The site datum will have a GPS location and will be shown on the site sketch.
5) Isolated Finds (IF) will be documented with a GPS location, description, and photograph when possible. Photographs are required for all formal or diagnostic tools. The Forest recommends use of the Ashley National Forest Isolated Find Form for documentation of IFs.

B. Site definitions

1) The field supervisor should always use professional judgment to help determine the level of documentation for cultural resources within the project area.
2) Cultural resources with the following attributes should be fully documented with a site form. Cultural resources that do not have any of the following attributes can typically be recorded as an IF.
   a) Prehistoric cultural site definition
      (1) More than 8 prehistoric lithic flakes within a 15m diameter area.
      (2) Any prehistoric feature or structure.
      (3) More than one prehistoric formal tool within a 15m diameter area.

(4) Presence of prehistoric ceramics in an area with cultural depth potential
(5) Presence of prehistoric groundstone in an area with cultural depth potential

b) Historic cultural site definition
   (1) A concentration of more than 50 historic artifacts with dates earlier than 1950.
   (2) A concentration of more than 10 artifacts with dates earlier than 1900.
   (3) Historic structures or features over 50 years of age.
   (4) Historic linear features (roads, fences, canals, etc.) with dates earlier than 1950 and which are named on historic maps.

C. Linear site guidelines
   1) Linear sites will be recorded, documented, and evaluated based on the Utah Professional Archaeological Council's "Linear Site Guidelines" whenever possible.

IV. National Register of Historic Places Evaluation

A. Each site will be evaluated for National Register of Historic Places (NRHP) eligibility and have a clear justification that explains the reasoning behind the eligibility. The eligibility justification will discuss specific National Register criteria and will address site integrity. Site forms cannot be submitted with an unevaluated or undetermined NRHP status.
   1) Sites which may be eligible for the National Register under Criterion D may require subsurface testing to determine eligibility. All subsurface testing will require a testing plan approved by the Forest Archaeologist. Where necessary for National Register evaluations, testing plans will be implemented before NRHP eligibility is determined.

V. GIS Data Collection.

A. Entities conducting cultural resource surveys on the Forest are authorized and required to gather and supply GIS data regarding cultural resource activities conducted on the Forest.
   1) Gather and provide GIS positional data to document survey locations, site locations, and isolated artifact locations for entry into the Heritage GIS database.
      a) Data must be collected using professional quality GPS units and must be differentially corrected.
      b) Collected positions will include information on time and date of collection, PDOP level, datum/coordinate system, and GPS unit used to gather the data. (Digital files from professional quality GPS units automatically include this information).
      c) Collected positions will include sufficient information to describe the GIS polygon, line, or point, including one or more of the following: site #, Project #, IF#, artifact #, etc.
      d) Permit holders are recommended but not required to use the Ashley Heritage Program Data Dictionary provided by Ashley National Forest.
   2) Recommended methods for GPS data collection:
      a) Linear survey – Gather points along the linear route, and then buffer according to width of transect (I.E. buffer 15m diameter or 7.5m radius for each person).
      b) Linear Features – Gather continuous points along the center-line if possible. Otherwise, gather points at beginning and end with selected points along the feature.

c) Artifacts, features, or structures less than 10m in diameter – Provide a point location and describe the areal extent in relation to the point.
d) Features or structures greater than 10m in diameter – Gather points as a line or polygon around the perimeter of the feature.
e) Sites – GPS a site boundary polygon and GPS a central site point (at site datum or at site center).
f) Block Surveys – Gather points at each corner and along the perimeter as needed to accurately define the survey block.

3) GIS data should be supplied to the Forest Archaeologist as soon the fieldwork is complete and prior to submitting the draft report for review.
   a) The most efficient method is to email the field-gathered GIS rover files and the resulting shapefiles to the Forest Archaeologist.
   b) The preferred format for GIS shapefiles is the NAD 83 UTM coordinate system.
4) GIS Data Quality
   a) The GPS/GIS data must meet or exceed the following standards for each position or feature collected:
      (1) Minimum of four satellites, 15º horizon mask, SNR >6, PDOP <6.
      (2) Minimum of 20 positions at one-second intervals to document a point feature.
      (3) Maximum of five-second intervals to document linear and polygonal features.

VI. Artifact Collection.

A. The Forest generally has a policy of not collecting artifacts except in cases of the following rare items. Artifact collection and analysis is required for:
   1) Diagnostic obsidian artifacts.
      a) A diagnostic obsidian artifact is defined as an identifiable tool which is attributable to a certain culture or time period (such as a projectile point), or obsidian debitage found within a feature that is attributable to a certain culture or time period.
      b) The location of collected obsidian artifacts will be documented with an accurate GPS location.
      c) The artifacts will be photographed, described, and documented.
      d) Artifacts will be promptly sourced through laboratory analysis and results included in the site report.
      e) The artifact will be curated at an appropriate facility.
   2) Representative ceramic artifacts.
      a) A ceramic artifact is defined as a sherd or a more complete ceramic artifact attributable to an identifiable prehistoric (non-Euro-American) culture or time period.
      b) The location of collected ceramic artifacts will be documented with an accurate GPS location.
      c) The ceramic artifacts will be photographed, described, and documented.
      d) Collected ceramics will be promptly submitted for petrographic analysis and results included in the site report. Thin sections will be returned to the Forest Archaeologist and the remaining ceramic sherd or vessel will be curated at an appropriate facility.

    e) If multiple ceramic sherds are present, collect one specimen from each distinctive vessel or ceramic type present.
  3) Diagnostic artifacts recorded as Isolated Finds that are located within an area of direct impacts (i.e. inside proposed well pad or road right of way).
- B. Artifacts outside of the preceding categories will only be collected under specific authorization from the Forest Archaeologist.

VII. Project Report

- A. The project report, site forms, and maps containing cultural resource information will be considered confidential information under the Archaeological Resources Protection Act and the report and maps will be labeled as such.
  1) Confidential information will not be disclosed or submitted to a third party without written authorization from the Forest Archaeologist.
- B. Survey Report Content
  1) Report format is versatile and at the discretion of the Consultant but must contain at least the following information:
    a) Description of the proposed project including anticipated nature of effects and Area of Potential Effects.
    b) Field methods (including survey requirements as listed in Section IV), list of field supervisors, list of field personnel.
    c) Discussion of each site encountered, NRHP eligibility recommendation and justification, and recommended mitigation or avoidance.
    d) Maps showing proposed project locations and inventory locations.
    e) Maps showing proposed project locations and all cultural sites.
    f) Maps showing Isolated Find Locations.
    g) Survey reports may be bound or unbound.
    h) SHPO Cover Page and any IMACS site forms must NOT be bound.
- C. Draft Report requirements for Cultural Resource Consultants.
  1) Consultants will send <u>one</u> draft copy of the report, complete with one draft copy of each site form for review by Ashley National Forest.
    a) The draft report and site forms may be submitted in a digital format to the Forest Archaeologist.
    b) The GIS data (as required in Section II.A.3) must arrive and be in the Forest database before the draft will be reviewed.
    c) If a draft hard copy of the report and site forms is provided, the draft copy need not meet archival standards.
- D. Final Report.
  1) Following approval of the draft report and site forms, the Consultant will provide copies of the final report and site forms to Ashley National Forest.
    a) The Forest Archaeologist will determine the needed number of paper copies of the Final Report and site forms (meeting archival standards).
  2) A CD or DVD containing digital copies of the final report and site forms will be provided to the Forest Archaeologist.
    a) The digital files must be submitted in an acceptable format, including PDF files or MS Word documents. Image formats can include PDF or JPG files.

b) Include the final versions of project shapefiles if any changes were made during review.

E. Ashley National Forest will submit the final report to SHPO and appropriate Tribes for review.

Attachment F

Archaeological Rules and Restrictions for Berry Petroleum Oil and Gas Development on Ashley National Forest Lands

Archaeological Rules and Restrictions for Berry Petroleum Oil and Gas Development on Ashley National Forest Lands

1. **Know where you can work.** Before you excavate or construct anything, make sure your work area is approved through the Surface Use Management Plan. (The approved area will be described in the well APD.)

2. **Know where you can drive.** Motor vehicles (including ATVs) are only allowed to drive on approved well pad access roads or on official Forest Roads (routes with road number signs). Driving any motor vehicles (including ATVs) off-road for any reason is not allowed.

3. **Do not collect arrowheads or other archaeological artifacts.** Collecting any archaeological artifact or damaging any archaeological site on public land is a violation of federal law and can result in fines and/or imprisonment for the individuals involved.

4. **Report archaeological finds.** If you find archaeological artifacts or human bones you must report them. ***If you accidentally damage an archaeological site within an approved work area, you will not be fined or punished if you immediately take the following steps:***

   A. First, stop all ground-disturbing activities within 100 feet (30m) of the discovery.
   B. Second, contact the project supervisor, who will contact the Forest Archaeologist.
   C. Third, do not start up work in that area again until the Forest Archaeologist gives permission.
   D. Never hide or cover up damage to archaeological sites.

5. **If you don't follow these rules, the following can happen:**

   A. Berry Petroleum can be cited for violating their drilling and operating permits.
   B. You can be fined or imprisoned for damage to an archaeological site.

I have read and understand the cultural resource restrictions for this project.

I agree to follow these rules whenever I am on Forest Service lands.

I agree to report any violations of these rules or illegal activities I witness on Forest Lands to appropriate Forest representatives.

Employee Name:____

Company Name:____

Employee Signature:__________________________ Date:__________

Attachment G

CULTURAL RESOURCE INADVERTENT DISCOVERY PLAN

CULTURAL RESOURCE INADVERTENT DISCOVERY PLAN

If unanticipated buried cultural resources are identified during project activities and construction, Berry will ensure that employees or contractors comply with the following protocol to ensure the proper identification, evaluation, and protection of the cultural resource.

Inadvertent Discovery of Cultural Resources

Project Supervisor or Contractor will <u>immediately</u>:

1. Cease all activity within 100ft/30m of the discovery.
2. Notify the Forest Archaeologist. The Forest Archaeologist will notify the SHPO, Tribe, and other consulting parties.
3. Notify the CR Consultant for the project
4. Leave all artifacts and materials in place but protect the discovery from further damage, theft, or removal.

The Cultural Resource (CR) Consultant will:

1. Document the discovery using site documentation specified in the Forest Guidelines for Documentation (Attachment E). This should also include, but is not limited to, documenting exposed artifacts and features; mapping the extent of artifacts, features, and cultural horizons; and documenting natural and cultural stratigraphy in open trenches or pits.
2. Evaluate the cultural resources for National Register of Historic Places (NRHP) eligibility and provide the documentation to the Forest Archaeologist. If an eligibility recommendation cannot be made based on the data collected during recordation, additional testing may be required to further delineate the nature, extent, and significance of the discovery. Testing will be limited to a sufficient level needed to provide a recommendation of NRHP eligibility.
3. If the cultural resources meet NRHP eligibility, the CR Consultant, under the direction of the Forest Archaeologist, will develop an action plan, mitigation plan, or emergency treatment plan for the affected cultural resources.

The Forest Archaeologist will:

1. Determine National Register eligibility and consult with the SHPO and Native American Tribes.
2. If the discovery contains human remains, the Forest Archaeologist will also follow the Discovery of Human Remains Protocol included below.
3. If associated or unassociated funerary objects or objects of cultural patrimony are discovered, the Forest Archaeologist will fulfill the requirements of NAGPRA as described in the Discovery of Human Remains protocol listed below.
4. If the cultural resources are ineligible for the National Register (with SHPO concurrence), work may resume with the CR Consultant monitoring for further cultural resource disturbances.
5. If the cultural resources are eligible for the National Register, the Forest Archaeologist will consult with the SHPO and consulting parties to avoid, minimize, or mitigate further effects to the Historic Property. Mitigation efforts may be contingent upon several factors, including the type and extent of the disturbed resource, the extent of the adverse effect, and whether or not it is possible to avoid any further effects to the resource.

Resumption of Work
1. Work in the immediate vicinity of the discovered materials may not resume until after the cultural resources are evaluated and adverse effects to Historic Properties have been avoided, minimized, or mitigated.
2. All costs related to the evaluation, analysis, and mitigation of the cultural materials will be borne by Berry.

Discovery of Human Remains

If human remains or remains thought to be human are identified during project activities and construction, Berry will ensure that employees or contractors comply with the following protocol in addition to the Inadvertent Discovery Plan described above.

Berry Project Supervisor or Contractor will
1. Ensure that employees or contractors do not take photographs of the human remains out of respect for Ute Tribal concerns and because of law enforcement forensic concerns.
2. Be responsible for the security and protection of human remains during NAGPRA consultations, until disposition of the remains is determined.

Forest Archaeologist will:
1. Notify appropriate law enforcement authorities and/or the County coroner about the human remains.
2. Work with law enforcement or the County coroner to determine age and affiliation of the human remains.
3. If law enforcement officials determine the human remains are not of recent age or criminal concern, the Forest Archaeologist will consult with affiliated Indian Tribes, SHPO, Utah State Antiquities Section, and other consulting parties to fulfill the requirements of NAGPRA (43 CFR 10).

The CR Consultant will:
1. Provide a specialist with expertise in human osteology and human remains to make an in-situ assessment of the remains, under the direction of the Forest Archaeologist, to document the remains and to determine cultural affiliation that would guide the development of a written Action Plan.
2. Under the direction of the Forest Archaeologist, develop an Action Plan for the evaluation and disposition of the Human Remains that meets the requirements of NAGPRA (43 CFR 10) and 36 CFR 800.

Resumption of Work
1. Work in the immediate vicinity of the human remains may not resume until after the disposition of the human remains is determined and a written binding agreement is executed between the necessary parties in accordance with 43 CFR Part 10.4(e).
2. All costs related to the evaluation, analysis, and disposition of the Human Remains will be borne by Berry.

United States
Department of
Agriculture

Forest
Service

February 2012

Appendix E
Response to Comments on DEIS

South Unit Oil and Gas Development
Final Environmental Impact Statement

Duchesne Ranger District, Ashley National Forest
Duchesne County, Utah

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	24	EPA	Svoboda	AA	EPA notes that the Final EIS and ROD must be clear regarding the number of wells and pace of development authorized as part of this action. Any change to the number of wells (either total number or number per year) would require additional NEPA compliance and air quality analyses.	The maximum number of well pads and wells is stated in each of the alternatives along with the range of wells anticipated to be drilled each year and the completion time for all well drilling (see Chapter 2 section 2.2 for detailed descriptions).
007	41	EPA	Svoboda	AA	EPA is concerned with the proposed loss of potential wilderness areas within the project area. As acknowledged in the Draft EIS, continued oil and gas development on Forest Service land nationwide could result in large-scale loss of areas with wilderness potential. The proposed project will contribute to this nationwide scale loss by loss of nearly all areas with wilderness potential within the project area. Consequently, we do not agree with the conclusion in the document that "the Proposed Action should not contribute significantly to cumulative impacts to Potential Wilderness Areas." We request that the Forest Service clarify and explain the grounds for this conclusion in the Final EIS.	Impacts to potential wilderness are disclosed in the EIS. Wilderness potential will not be lost, the impacted areas will no longer meet mapping criteria in the potential wilderness inventory. Furthermore, the condition of the land today will not be the same as the condition of the land in the future. Cumulatively, some of the land may have recovered by the time the project is complete.
007	42	EPA	Svoboda	AA	…EPA does not agree with the characterization in the Draft EIS of all project alternatives as having equal impact on potential wilderness areas. While we recognize that a minimum acreage is necessary to manage an area as wilderness, and that any surface-disturbing activities will result in loss of wilderness attributes, we believe that critical environmental attributes can still remain after development. Oil and gas development in potential wilderness areas should consequently be planned and managed to preserve these attributes to the maximum extent practicable. EPA recommends that travel management planning avoid road development in semi-primitive (especially semi-primitive non-motorized) areas wherever possible. We further recommend that well pads be placed outside of these areas wherever directional drilling could feasibly be used to extract their minerals. These measures will aid in preventing habitat fragmentation and preserving ecological processes. In planning the locations of all surface disturbing activities, the Forest Service should additionally consider watershed protection, and avoid construction in drainages, on steep slopes, or in areas of erodible soils. We have discussed watershed protection in detail under 'water resources' in this letter, but note here that it is of particular importance where development will occur in potential wilderness areas, to preserve their valuable roadless qualities for maintenance of watershed health.	The effects analysis has been rewritten to better reflect the effects of the project to wilderness attributes. Since potential wilderness is an inventory based on criteria that includes the size of the area bearing inventory qualities, the EIS discloses that future inventories may not include areas disturbed in and around the project development due to the likely reduction of contiguous acres with those qualities under each of the action alternatives. The ANF has a travel management plan that dictates how Forest Roads are managed. New project-related roads will be built and maintained by the project proponent and will not be accessible to the public. These roads will be fully reclaimed once they are no longer needed and the project is complete. Where feasible, roads and well pads will be placed away from drainages, steep slopes, and erodible soils, and directional drilling will be used to relocate and co-locate well sites, in order to minimize impacts.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	1	UEC, WG, SUWA, WRA, WWP		AA	The Forest Service has not established compliance with the Reform Act in the South Unit EIS. For example, the agency has not adequately identified and required alternatives that ensure that any development in the project area:-minimizes effects on surface resources-does not result in unreasonable surface resource disturbance-prohibits operations in riparian areas and wetlands-prohibits operations in areas subject to landslides-to the extent consistent with the rights conveyed by the lease, is consistent with, or is modified to be consistent with, the applicable current approved forest land and resource management plan.In addition, the Forest Service must identify, analyze and consider alternatives that exceed these minimum requirements and where appropriate, require the adoption of such an alternative.	See responses to more specific comments regarding the Reform Act.
005	11	Duchesne County Commission	Hyde	ALT	We note on Page 31 of the DEIS that the preferred alternative will allow 400 wells on up to 162 well pads. Including roads and compressor stations, the total long-term surface disturbance is only 462 acres of the 25,920 acre project area (only 1.8% of the area would be disturbed long term). This minor amount of surface disturbance, together with the mitigation measures/stipulations, will ensure that the project is conducted with the least possible impact on the environment including, but not limited to, wildlife, recreation and visual resources.	Support for the Preferred Alternative noted.
006	1	State of Utah, Public Lands Policy Coordination	Harja	ALT	The State of Utah supports the selection of Alternative 4 as the Preferred Alternative. The Preferred Alternative accommodates issues of concern such as habitat fragmentation and air quality while supporting the reasonable development of energy resources vital to the economy of the area.	Support of Preferred Alternative noted.
006	25	State of Utah, Public Lands Policy Coordination	Harja	ALT	There are four potential wilderness areas within the project area. Each of these has their "undeveloped character affected by fences, water developments for grazing, gas well sites and the sights, sounds, and smells of motorized activities on nearby roads and trails throughout the year." These areas "exhibit characteristics that make it difficult to manage as wilderness" (3.13.1.3.1, 3.13.1.3.2, 3.13.1.3.3, 3.13.1.3.4) The state strongly encourages Department of Agriculture Secretary Vilsack to approve the limited road construction needed to support the preferred alternative which has nearly half the amount of surface disturbance and road mileage as the proposed alternative.	Support for Preferred Alternative noted.
007	23	EPA	Svoboda	ALT	EPA is pleased with the selection of Alternative 4, the reduced surface disturbance alternative, as the Preferred Alternative for the proposed Project. However, EPA recommends that the Forest Service consider incorporating into the Preferred Alternative many of the excellent protective measures proposed in the Phased Drilling Alternative. Phased drilling reduces surface disturbance exposed at any one time and minimizes wildlife impacts. The additional best management practices (BMPs) proposed for consideration in the Phased Drilling Alternative should also be incorporated into and required for the Preferred Alternative. Particularly, we note that drilling multiple wells on an individual well pad (already part of the Preferred Alternative), centralized production facilities, closed loop drilling and minimizing topsoil removal during drilling activities alleviate many of EPA's primary concerns typically associated with oil and gas development.	Your support for Alternative 4 and suggested changes have been noted.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	25	EPA	Svoboda	ALT	EPA understands that 25 wells originally included in the Operator's plan for development in the ANF South Unit have been authorized by Categorical Exclusion under the Entergy Policy Act of 2005. These wells were approved in 2009, and development will likely occur before completion of the NEPA process for the proposed South Unit Project. Because development of these additional 25 wells will occur regardless of the outcome of the NEPA process for the proposed project, they should be incorporated into the No Action Alternative. Discussion of the No Action Alternative in the Final EIS should include the 25 additional wells and all associated facilities, with an explanation of their origin. Further, discussion of the action alternatives should make clear whether development of 400 or 375 additional wells is under consideration in this EIS.	This information has been updated in Section 2.2.1 Alternative 1 - No Action and includes 29 well pads, 39 miles of existing roads and 74 wells either in production or approved for drilling, but not yet drilled. The action alternatives state that 400 wells represents a full development scenario and of these 400 wells, 44 have already been approved for drilling under separate, site-specific NEPA analysis.
007	26	EPA	Svoboda	ALT	We recommend that the Forest Service reconsider the possibility of incorporating a surface disturbance cap into the Preferred Alternative. According to the Draft EIS, a cap on surface disturbance was not carried forward for detailed analysis because the alternatives considered already contain limitations for surface disturbance. However, a cap on surface disturbance increases interim reclamation efforts and reduces the amount of disturbed soil at any one time, minimizing impacts to water quality and wildlife. EPA recognizes that other more active management strategies may be more effective at targeting and minimizing particular impacts than solely relying upon a surface disturbance cap. Consequently, we recommend that the Forest Service consider how the valuable components of a cap on surface disturbance can be incorporated and enforced in the Preferred Alternative through phased drilling, such as establishing interim reclamation requirements for each phase.	The maximum amount of surface disturbance proposed for each alternative is covered under the alternatives analysis. Alternative 3 is a phased development alternative that covers a disturbance cap. Non-productive wells will be immediately reclaimed and interim reclamation is required under the BLM onshore orders and in the project reclamation plan.
004	3	U.S. Department of Interior, Office of Environment	Stewart	AQ	Because some of the "level of analysis decisions" made for the air quality analysis in this DEIS may be precedent setting and determine how BLM can and should conduct future analyses of impacts on air quality, BLM requests the opportunity to participate in responding to any comments from EPA Region 8 or the public on the air quality analysis in the DEIS.	EPA's comments on the DEIS have been addressed. The EPA, BLM, and FS have an MOU in place now, specifically dealing with air quality issues and concerns.
004	13	U.S. Department of Interior, Office of Environment	Stewart	AQ	Pages 70 and 71, Air Quality: The DEIS tiers to the Uinta Basin Air Quality Study (UBAQS, Page 71) for an examination of regional cumulative ozone impacts. A discussion of EPA's concurrence on the application of the UBAQS study is needed. Specifically, has EPA Region 8 specifically stated this is sufficient for this project?	EIS has been updated with information on FS's agreement with EPA on modeling ozone.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	14	U.S. Department of Interior, Office of Environment	Stewart	AQ	An incremental cumulative impact analysis for ozone was not conducted since the project emission inventory "contributions are unlikely to be noticeable in the model compared to cumulative contributions" (pg 70, line 28). The DEIS states that the determination was agreed to between EPA Region 8 and the FS in June 2009. Consistency between the Federal Land Managers and EPA is needed to determine thresholds for photochemical grid modeling. However, in this DEIS the FS and EPA seem to set one through this determination. Additional information should be added to describe how this determination was made. Explain if it was based on the uncontrolled emission inventory, the controlled emission inventory, the proposed well count (400 wells) or some other parameters.	The ozone section has been updated with justification for the level of analysis.
004	15	U.S. Department of Interior, Office of Environment	Stewart	AQ	A statement is made that ozone concentrations in the Uinta Basin are well below the NAAQS (pg 70, line 25). Recent monitoring near Ouray and Redwash in Uintah County contradicts this. The FEIS should report the results of this recent monitoring.	Ouray and Redwash information added to the EIS.
004	16	U.S. Department of Interior, Office of Environment	Stewart	AQ	It is not clear what is meant by a "qualitative ozone analysis" (pg 70, line 39). The FEIS should explain whether the emission reduction percentages contained in the operator committed controls is the qualitative assessment. The emission reduction percentages demonstrate a reduction in ozone precursors, but the DEIS does not analyze of the impact of that reduction. The impacts of reduction of ozone precursors should be addressed in the FEIS.	The ozone analysis has been revised and updated.
004	17	U.S. Department of Interior, Office of Environment	Stewart	AQ	Background PM2.5 values are not given in the DEIS, ("not provided by UDAQ"). The predicted maximum concentrations of PM2.5 are then given as the project specific concentrations (not added to a background value). A discussion on how this approach is appropriate or required should be included in the FEIS. There are monitored PM2.5 values available for the city of Vernal in Uintah County that show exceedence level values in the winter months. This may need to be included in the discussion.	The Project Emissions section has been updated with PM2.5 values.
005	16	Duchesne County Commission	Hyde	AQ	Since scoping for this project began in 2007, the project has been held up pending completion of an air quality analysis. We are pleased that this analysis has been completed and that the modeling results show that "neither direct project impacts nor cumulative source impacts would exceed any air quality standard.."	Noted.
006	17	State of Utah, Public Lands Policy Coordination	Harja	AQ	The state of Utah supports the mitigation measures listed in Section 2.2.5 as a means of improving air quality in Utah. The consistent use of best management practices provides the best opportunity for proactively addressing potential air quality concerns.	Noted.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	18	State of Utah, Public Lands Policy Coordination	Harja	AQ	Pg 65, 3.2.2.2.1, "a central compressor station would be located near a well pad.." This text clearly states that the modeled scenario is for 1 well pad with associated compressor station and roadway. In the state's initial comments, dated January 13, 2009, it was recommended that a cumulative modeling scenario would more likely reflect air quality impact, and should be performed. The state requests the FEIS provides a clarification of the number of wells included in the model.	The model assumes that 400 wells are constructed at an even pace of 20 wells per year for 20 years. Production emissions for the Project will increase each year, with the final year (year 20) having the largest production emissions. For additional details, please see the Air Quality Technical Support Document, included as Appendix C in the FEIS.
006	29	State of Utah, Public Lands Policy Coordination	Harja	AQ	Reference to UAAQS throughout both volumes should be deleted or better explained. Utah did not publish its own ambient air quality standards. Utah applies the EPA national NAAQS. There is no benefit to including the "UAAQS" label in the tables. It is more appropriate to use the NAAQS.	Not all states use the NAAQS, some state standards are more stringent than the national standards, as demonstrated by the Colorado standards shown in the same table. Using the UAAQS makes it clear to all readers that the Utah standards are the same as the national standards.
006	30	State of Utah, Public Lands Policy Coordination	Harja	AQ	Table 3-9 and 3-10. EPA finalized the PM2.5 standard to 35ug/m3 on 12/17/06. Including the older standard is confusing.	PM2.5 analysis has been updated.
006	31	State of Utah, Public Lands Policy Coordination	Harja	AQ	On page 56, Table 3-5 and page 68, Table 3-11 the TSL values are cited as mg/m3. The TSL values should actually be in ug/m3. The TSL hexane value in both tables 3-5, 3-11, and in Appendix H on page 21, Table 9 are in error. 14466.7 should be 5875.	Changes made.
006	35	State of Utah, Public Lands Policy Coordination	Harja	AQ	In Appendix H, Table 6, page H-15, Is carbon monoxide supposed to be 1145 ug/m3 = 1 ppm? Citations for 2 & 5 are missing.	Changed to 1145
007	44	EPA	Svoboda	AQ	EPA therefore believes that omission of values for PM2.5 and ozone from the table of background ambient air quality concentrations (Table 3-3) is not appropriate given the current level of regional concern…. We recommend that the Forest Service use values obtained in the past year at newly installed monitors in the Basin if possible, or else use values from Canyonlands National Park, which is the nearest site where validated data can currently be obtained.	The air section has been updated. Background PM2.5 values have been added to the analysis.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	45	EPA	Svoboda	AQ	Regarding the discussion of ozone (section 3.2.2.3.5 under Environmental Consequences?), EPA must object to some of the language used in the Draft EIS. EPA does not agree the “quantitative ozone modeling is not appropriate for this scale of development” as is suggested on pg. 70. The potential for impacts from oil and gas development does not depend upon the number of wells alone. Many factors, including existing ambient air conditions, density of development, pace of development, proximity of sensitive areas, and emission reduction measures implemented during development and production, are relevant to whether a project may have potential for air quality impacts. A 400 well project does have potential to contribute to significant impacts to ambient ozone concentrations. For the South Unit Project, EPA did work with the Forest Service during the scoping phase to recommend appropriate mitigation measures to minimize ozone impacts. Neither EPA nor the Forest Service was aware of the ozone conditions in the Uinta Basin during the scoping phase for this project. At that time, EPA agreed that aggressive mitigation and monitoring to minimize ozone impacts, combined with a qualitative ozone analysis could allow the Forest Service to reasonably conclude that no significant impact would occur due to this particular project. To address EPA’s concerns regarding recent elevated measurements of ozone in the Uinta Basin, the Forest Service should strengthen the analysis of ozone impact in the Final EIS. Specifically, a table should be prepared that presents the overall ozone precursor (NOx and VOCs) emission reductions achieved fro the mitigation measures identified in Section 2.2.5. This table should clearly present, by source category, controlled and uncontrolled emissions. The table should also detail the total project controlled and uncontrolled emissions and associated emission reductions. These emission figures should be presented in a consistent form relevant for comparing to other emission sources, such as tons per year, and be made available for other future project cumulative ozone analysis work. The emissions table summary should be performed for each alternative for comparison purposes. Further, we recommend the Forest Service use the results of this calculation to more clearly explain in the Final EIS why the South Unit Project will not cause significant ozone impacts.	The ozone analysis has been updated taking into consideration your recommendations.
007	46	EPA	Svoboda	AQ	Given recent ambient concentrations of ozone measured in the project area, which exceed the NAAQS, the EIS should identify the project’ contribution to this serious problem…. If the project has potential to significantly contribute to ozone in the Uinta Basin, we recommend that ozone modeling be considered to more accurately quantify predicted contributions before proceeding to the Final EIS.	Following thorough consultation with state and federal agencies including EPA, Photochemical modeling was considered but not selected as an analysis tool for this EIS. However, since ozone is a concern, a conservative and preemptive mitigation and monitoring approach was selected in tandem with qualitative analysis. The EPA was intimately involved in assisting the USFS in developing the details of this approach to ensure it met their satisfaction.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	47	EPA	Svoboda	AQ	We also note that, while the proposed list of required air quality mitigation measures is already more than commonly applied to oil and gas development projects, there are additional opportunities for VOC and NOx emissions reductions. These potential additional mitigation measures may include: Reducing pace of development; using Tier III or higher drilling rig engines; upgrading pump jack engines to meet all future New Source Performance Standards or electrifying pump jacks; installing a liquids gathering system for produced water and condensate fluids; using a Centralized Automation System to transmit information to a centralized location for monitoring and controlling gas operations, which will reduce mobile source traffic in the field; and using emission controls on all produced water tanks, and reducing use of all produced water holding ponds.We also recommend that the Forest Service look at EPA's Natural Gas STAR Program and Four Corners Task Force Recommendations for additional mitigation measures.	Your recommendations have been noted.
007	48	EPA	Svoboda	AQ	We recommend that the air quality chapter of the document reference Section 2.2.5 – Mitigation Common to All Alternatives which contains many relevant mitigation measures, a s well as a detailed explanation of the proposed leak detection program.	Change made.
007	49	EPA	Svoboda	AQ	We recommend including a more comprehensive discussion of how leak detection and monitoring, which should include PM2.5, would be used to mitigate air quality impacts. This discussion should include trigger points and additional mitigation measures that will be incorporated in case a problem is identified, similar to an adaptive management plan. We additionally recommend that the Forest Service consider additional unpaved road treatment such as the application of chemical dust suppressant agents and reducing vehicular speeds, which may be effective in mitigating the particulate matter impacts. We note that the dust plan developed in the recent programmatic agreement for the West Tavaputs Plateau Development is a good source of information on locally-relevant dust suppression alternatives.	Your recommendations have been noted.
007	50	EPA	Svoboda	AQ	Measures to ensure compliance with proposed mitigation techniques should be provided in the Final EIS and ROD.	Noted.
007	51	EPA	Svoboda	AQ	…Given our significant concerns with UBAQS, as well as the fact that 2012 is now only two years away and will not be the maximum emission year for the South Unit Project, we question the value of including the findings of this study in the Draft EIS.	The UBAQS was reviewed and included in the EIS per the CEQ guidance on incomplete information.
007	52	EPA	Svoboda	AQ	….While direct project emissions are not exceeding DATs, the South Unit Project is contributing incrementally to a cumulative adverse impact. We recommend that the Forest Service take this into consideration when considering mitigation measures that would reduce Nitrogen, such as NOx emissions controls. EPA is additionally concerned that direct project impacts are predicted to result in visibility impacts at several sensitive Class II areas, according to Appendix H. Inclusion of further mitigation measures to reduce these adverse impacts is recommended.	Your recommendations have been noted. Various mitigations have been added to this project to minimize impacts to air quality.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	53	EPA	Svoboda	AQ	Inclusion of new 1 hour NO2 NAAQS was not addressed in the Draft EIS. We recommend that the 1 hour NO2 air impact analysis be included if reasonable possible.	The FEIS has been updated to evaluate both the 1-hour NO2 and 1-hour SO2 impacts in order to assess the impacts of the Project against all applicable new NAAQS.
010	66	UEC, WG, SUWA, WRA, WWP		AQ	Duty to Protect Air Quality under NFMA and Its Planning Regulations. We appreciate the Forest Service's (USFS) attention to addressing the air quality impacts of oil and gas development on the Ashley National Forest. As the agency knows, air quality is increasingly a concern in the American West, generally, and in the Uintah Basin, specifically, as industrial development has increased. Studies show that more and more regions of the West are projected to violate various air quality standards. Monitoring from the Uintah Basin shows that this area is already exceeding certain air quality standards. Therefore, it is critical that the USFS undertakes a comprehensive and detailed air quality analysis to determine potential impacts that might result and avoid those impacts forbidden by the USFS's regulations. The USFS has a substantive duty to protect federal and state air quality standards. This duty is affirmed in the relevant planning regulations at 36 CFR § 219, which require that all management prescriptions "[Ile consistent with maintaining the air quality at a level that is adequate for the protection and use of National Forest Systems and that meets or exceeds applicable Federal, State and/or local standards or regulations." 36 CFR § 219.27(a)(12). Furthermore, the USFS's mineral development regulations at 36 CFR § 228 require that the agency ensure that operators comply with "Federal and State air quality standards[.]" 36 CFR §§ 228.8(a) and 228.112(c)(1). In this case, the USFS not only has a duty to analyze air quality impacts, but to demonstrate that the level of oil and gas development authorized through the South Unit DEIS will protect air quality standards, primarily including National Ambient Air Quality Standards ("NAAQS") and Prevention of Significant Deterioration ("PSD") increments established by federal regulation.	Compressive AQ analysis is contained in the Air Quality Technical Support Document, included as Appendix C in the FEIS.
010	67	UEC, WG, SUWA, WRA, WWP		AQ	Additionally, the USFS must ensure that the air quality related values (AQRVs) of the nearby High Uintas Wilderness Area and Flaming Gorge National Recreation Area (NRA) are protected, as well as the AQRVs of relevant Class I areas. The Ashley National Forest's Forest Plan for Land and Resource Management Plan ("Ashley RMP") commits the USFS to "[p]reserve and protect air quality related values ... within the Flaming Gorge NRA and the High Uintas Wilderness." Ashley RMP at IV-42 (1986), available at http://www.fs.fed.us/r4/ashley/projects/lrmp/19861rmp.shtrn . Federal and state air quality standards, which the USFS must observe, also include protecting the AQRVs of Class I areas such as Canyonlands National Park. See Utah Air Quality Board, Utah State Implementation Plan, Section VIII, Prevention of Significant Deterioration 2 (Mar. 8, 2006), available at http://www.airguality.utah.gov/Planning/SIP/SIPPDF/SecVIII¬PSD.pdf.	Noted.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	68	UEC, WG, SUWA, WRA, WWP		AQ	To meet its substantive duties, the USFS cannot simply defer to state or federal regulations to demonstrate that the NAAQS and PSD increments for pollutants under the Clean Air Act will be protected. This is because of the following reasons: NEPA requires the USFS to undertake a careful examination of the direct, indirect and cumulative environmental impacts of its proposed actions; Utah has not had a network of air quality monitors in the areas relevant to this action sufficient to determine compliance with NAAQS. Moreover, historically, the relevant area that monitors ozone—Dinosaur National Monument—has done so largely in the summer. Recent air quality analysis in and around oil and gas development fields show that ozone concentrations can exceed NAAQS in the winter - when the nearby ozone monitor has been off line. States, including Utah, have not yet submitted State Implementation Plan ("SIP") revisions to the U.S. Environmental Protection Agency ("EPA") pursuant to Section 110 of the Clean Air Act to ensure attainment and maintenance of the ozone and PM2.5—particulate matter less than 2.5 microns in diameter—NAAQS, meaning no analysis or finding has been made showing that current state air quality rules are sufficient to ensure compliance with these NAAQS; • The State of Utah permitting requirements do not apply to stationary sources that emit 5 tons per year or fewer of any criteria pollutant (see Utah Administrative Code R307-401-9) and only require an analysis of ambient air quality impacts if a source releases more than 40 tons of nitrogen oxides, 5 tons of fugitive particulate matter less than 10 microns in diameter ("PM10"), and 15 tons of non-fugitive PMIo (see Utah Administrative Code R307-410-4). Furthermore, State of Utah permitting requirements do not actually require any analysis of impacts to ozone or to PM2.5. • The State of Utah is failing to permit stationary oil and gas production facilities in accordance with PSD requirements under the Clean Air Act and EPA guidance. Namely, the State of Utah is not appropriately identifying stationary sources consistent with the regulatory definition of a stationary source, which is any "building, structure, facility, or installation," including "all of the pollutant emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control." See 40 CFR §§ 51.166(b)(5) and (b)(6). The EPA recently reaffirmed the need for States to appropriately define oil and gas sources consistent with this definition. See Memo from Gina McCarthy, Asst. EPA Administrator to Regional Administrators, "Withdrawal of Source Determinations for Oil and Gas Industries" (September 22, 2009), available at http://www. pea. go v/region/air/nsensrmemos/oilgaswithdrawal.pdf. Unfortunately, the State of Utah is not complying with this EPA guidance and is, as a result, failing to permit oil and gas stationary sources as dictated by the Clean Air Act. The State of Utah does not limit emissions related to vehicle tailpipes or fugitive dust or particulate matter to ensure compliance with the NAAQS. • The State of Utah does not otherwise address the cumulative impacts of oil and gas development to air quality. Although the State has a permitting program, this program only applies to single stationary sources that "consume increment" and does not address emissions from older stationary sources or from oil and gas development in the aggregate on a regional level. In light of these shortcomings in Utah's air quality regulations, it is incumbent on the USFS to prepare a detailed analysis of an quality impacts and to take steps to limit such impacts to protect air quality standards, including the NAAQS and PSD increments. Furthermore, the	See Air Quality Technical Support Document (Appendix C in the FEIS) as well as the operator-committed ozone reduction mitigation measures.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
					USFS has a self-imposed duty—independent of any State of Utah obligation—to ensure that its actions do not harm AQRVs in the High	

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	69	UEC, WG, SUWA, WRA, WWP		AQ	The South Unit DEIS Does Not Adequately Analyze Fine Particulates; This Region Is Already Experiencing Levels of Fine Particulates in Excess of Federal Standards. Particulate matter is one of six NAAQS "criteria" pollutants regulated under the Clean Air Act. See 42 U.S.C. § 7273(b)(4); 40 C.F.R. §§ 50.6, 50.7, and 50.13. In addition, particulate matter is certainly an issue of material significance as it is extremely harmful to human health; both short-term and long-term exposure to particulate matter can lead to increased premature mortality, increased hospital admissions and emergency room visits, and the development of chronic respiratory disease. See National Ambient Air Quality Standards for Particulate Matter, 71 Fed. Reg. 2,620, 2,620 (January 17, 2006). The NAAQS limits for the maximum 24-hour average of PM2.5 is 35 ug/m3. See id; South Unit DEIS at 54.PM2 5 includes all particles less than 2.5 microns in diameter, or 1128th the width of a human hair. Although PM2 5 can be directly emitted, it can also form in secondary reactions in the atmosphere. 1 According to EPA, the health effects of PM2.5 include:• Increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing; Decreased lung function; Aggravated asthma;• Development of chronic bronchitis;• Irregular heartbeat;• Nonfatal heart attacks; and• Premature death. 2). The South Unit DEIS, as it currently stands, violates the National Environmental Policy Act (NEPA) because it has failed to include background concentrations of the Clean Air Act's NAAQS criteria pollutants for fine particulate matter, or PM2 5—referring to particulates 2.5 microns in diameter or smaller. Background concentrations for this pollutant must be included to accurately assess air quality impacts in the area from oil and gas development. This pollutant has recently been monitored at levels exceeding federal air quality standards.	PM2.5 analysis has been added to EIS

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	70	UEC, WG, SUWA, WRA, WWP		AQ	The South Unit DEIS incorrectly suggests that site-specific monitoring data for NAAQS criteria pollutants is not available in the area. See South Unit DEIS at 53. It relies exclusively on figures that it obtained from the Utah Division of Air Quality (DAQ). However, this completely overlooks the fact that a PM2.5 monitor has operated in Vernal during at least portions of the last three years. This monitor is sufficient to provide the USFS with the necessary background data for determining PM2.5 concentrations. DAQ operated a PM2.5 monitor in Vernal from approximately December 2006 to December 2007 which showed that PM2.5 concentrations in the Uintah Basin often significantly exceed NAAQS. See DAQ, Particulate PM2.5 Data Archive, http://www.airmonitoring.utah.gov/dataarchive/archpm25.htm (showing concentrations substantially higher than 35 µg/m3, the 24-hour average maximum NAAQS limit, particularly during January and February 2007); see, e.g., South Unit DEIS at 54 (stating that NAAQS for the 24-hour maximum average of PM2.5 is 35 µg/m3). Air quality monitoring data from the DAQ's Vernal monitor during that time showed that P.M2.5 has reached concentrations as high as 63.3 µg/m3. DAQ, Particulate PM2.5 Data Archive, January 2007, http://www.airmonitoring.utah. Gov/data archive/PM25JAN07.1)do In 2008, DAQ operated a monitor in Vernal, Utah during February and March. See Letter from Stephen S. Tuber, EPA, to David Garbett, Southern Utah Wilderness Alliance 2 (Sep. 3, 2009) (See attached, Exhibit 1). In that short period the DAQ's Vernal monitor recorded once exceedence of the NAAQS for the 24-hour maximum average of PM2.5. Id. Finally, in 2009, monitors in the area recorded further exceedances of NAAQS. From a period spanning a part of 2009, January 21 to March 5, a Vernal monitor operated by Utah and funded by the EPA recorded four exceedances. Letter from Tuber to Garbett at 2. During that same period a monitor in Roosevelt recorded three exceedances of the 24-hour maximum average value for PM2.5. Id. The high concentration observed in Vernal was 60.9 µg/m3 and the high concentration recorded in Roosevelt was 42.4 µg/m3, both well in excess of NAAQS. See id. These values demonstrate that monitoring data is available for PM2.5 for the Uinta Basin. Furthermore, and most importantly, they show that current maximum concentrations of PM2.5 are at a level detrimental to human health and the environment. To adequately protect human health and understand the true environmental impacts of this project the USFS must adopt a PM2.5 baseline for purposes of modeling that is more reflective of the actual data collected in the area. This means that the South Unit DEIS should have used a baseline with either the highest (63.3 µg/m3) or second highest (60.9 µg/m3) concentration reading from the Vernal monitor. See supra.	Between 2008 and July 2010, additional monitoring and modeling were carried out in the Uinta Basin, and the Utah DAQ was able to recommend a PM2.5 background. Therefore the text has been revised.
010	71	UEC, WG, SUWA, WRA, WWP		AQ	The USFS must also show that this project will not lead to further exceedances of NAAQS, something very difficult to envision based on current conditions in the Uinta Basin. The South Unit DEIS currently predicts that construction phase of this project will result in an increase of 11.82 .if/m3 to the 24-hour maximum average of PM2.5 and that the production phase will result in an increase of 1.40 µg/m3. South Unit DEIS at 66-67. Adding the increases from either of these phases will only exacerbate the poor air quality of the region and will certainly exceed NAAQS, since the current background is between 63.3 µg/m3 and 60.9 µg/m3 and NAAQS is 35 µg/m3. See supra.	NAAQS compliance is shown in Table 3-9 and Table 3-10.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	72	UEC, WG, SUWA, WRA, WWP		AQ	The South Unit DEIS completely ignores the impacts of secondary PM2.5 formation. This oversight represents a critical flaw in this analysis as secondary formation may be the principal cause of the elevated levels of PM2.5 that have been observed in the region. The USFS must rectify these NEPA violations by taking a hard look at fine particulate pollution in the region and the effect this project will have on those concentrations. The USFS must adopt monitoring values from the Uinta Basin for its background concentrations of PM2.5. It must also model secondary PM2.5 formation.	PM2.5 analysis has been added to EIS
010	73	UEC, WG, SUWA, WRA, WWP		AQ	The South Unit DEIS Fails to Adequately Analyze Ozone Impacts.Oil and gas development in the American West is increasingly impacting ambient' ozone concentrations, in many cases contributing to exceedances or violations of the ozone NAAQS .3 This is largely due to the cumulative nature of an quality impacts from oil and gas development. While one oil or gas well is a relatively small source of air pollution, thousands of wells and associated equipment and activities amount to very large sources of air pollution. Importantly, while the NAAQS limit ozone concentrations to no more than 0.075 parts per million (ppm), the EPA has proposed to establish an even lower NAAQS of between 0.060 and 0.070 ppm .4 Under the proposed standards, a number of regions in the Rocky Mountain West that have never exceeded or violated the ozone NAAQS are expected to do so.Unfortunately, no entity has addressed the cumulative nature of air pollution— particularly for ground level ozone—from oil and gas development, making it all the more critical for the USFS to fully account for air quality impacts. This need is bolstered by a recent study on the impacts of oil and gas development to ozone formation in the West, which found:A regional air quality model has been applied to the western United States to investigate the impacts of emissions from oil and gas development on 03 [ozone] concentrations. Incremental 03 increases (8-hr average) ranging from less than 1 to 7 ppb were predicted at several western Class I areas, and a peak incremental 03 concentration of 10 ppb was simulated in the Four Corners region. This study, although not exhaustive, does indicate a clear potential for oil and gas development to negatively affect regional 03 concentrations in the western United States, including several treasured national parks and wilderness areas in the Four Corners region. It is likely that accelerated energy development in this part of the country will worsen the existing problem. 5 To this end, it is critical that the USFS fully analyze and assess the direct, indirect, and cumulative impacts of oil and gas development to ozone concentration, and ensure that steps are taken to mitigate such impacts. Unfortunately, the South Unit DEIS falls short of meeting this basic responsibility.---3 The ozone NAAQS is based on an eight-hour average of hourly monitored values. An exceedence of the ozone NAAQS occurs whenever eight-hour ozone concentrations rise above the level of the NAAQS. A violation of the ozone NAAQS occurs only when the three year average of the fourth highest eight-hour value at any monitoring site exceeds the NAAQS. See 40 CFR § 50.15.4 See National Ambient Air Quality Standards for Ozone, Final Rule, 73 Fed. Reg. 16,436, 16,436 (Mar. 27, 2008) (establishing current ozone standard); EPA, "National Ambient Air Quality Standards for Ozone, Proposed Rule," 75 Fed. Reg. 2930-3052 (discussing proposed lower standard).5 See Rodriguez, et al., "Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States," Journal of the Air and Waste Management Association, Vol. 59, 1111-1118 (September 2009) at 1118, available online at	The ozone analysis has been revised.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	74	UEC, WG, SUWA, WRA, WWP		AQ	The South Unit DEIS Fails to Adequately Analyze and Assess Ozone Impacts. The South Unit DEIS fails to analyze and assess impacts to ambient concentrations of ozone air pollution. As the USFS notes, ozone is a pollutant of concern for which the Clean Air Act has established NAAQS. Two key air pollutants — volatile organic compounds (VOCs) and nitrogen oxides (N0x) — react with sunlight to form ozone. Nevertheless, USFS fails to analyze potential impacts to ambient concentrations of ozone. The USFS must analyze ozone concentrations that will result from the construction and production of the wells associated with this project. Because of the complex relationship between ozone precursors and ozone formation, ozone concentrations can only be predicted through quantitative dispersion modeling. See, e.g., Bureau of Land Management, Moab Proposed Resource Management Plan and Final Environmental Impact Statement, Comments of the Draft EIS by Resource Type 70 (Aug. 2008) available at http://www.blm.gov/pgdata/etc/medialib/b1m/ut/moab of/ramp/finale is. P ar. 90116. File. Data/ ResponseByResource.pdf ("Predicting ozone associated with oil and gas development requires air dispersion modeling."). The South Unit DEIS does not include quantitative dispersion modeling for ozone. South Unit DEIS at 70. Rather than conduct modeling to analyze ozone concentrations, the USFS suggests that ozone analysis would not be proper with the South Unit DEIS. See South Unit DEIS at 70. However, this position fails to meet the obligations that the USFS has under NEPA to take a hard look at the impacts from oil and gas development on ozone pollution and to describe how this action will relate to other federal laws (in this case, the Clean Air Act and its NAAQS for ozone). Although the USFS essentially assures the public that there will be no violation of any NAAQS standard, see, e.g., South Unit DEIS at 66, the agency has not provided any evidence to support this conclusion as it is legally required to do. See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983). Only quantitative ozone dispersion modeling can assure the public that ozone NAAQS will not be exceeded. See supra. The South Unit DEIS does not contain ozone dispersion modeling, the USFS has never conducted ozone dispersion modeling in the Uinta Basin, and the Bureau of Land Management—a sister agency with even larger oil and gas holdings in the Uinta Basin—has never conducted ozone dispersion modeling in this region. Thus, there is no way for the USFS to assure the public that oil and gas development from this project will not violate NAAQS. In fact, the only regional dispersion modeling that has been prepared for this area, the Uinta Basin Air Quality Study (UBAQS), predicts that the project area will exceed NAAQS in 2012.6 The South Unit DEIS even references and attempts to rely on UBAQS. See South Unit DEIS at 71-72. UBAQS, based on 2006 meteorological data, predicts that ozone levels in the project area will likely exceed current ozone NAAQS. See UBAQS TS-29 (June 30, 2009), available at http://ipams.org/wp¬content/uploads/UBAQS Final Report Jun30_2009 pdf UBAQS modeled that ozone levels in the project area were likely violating current ozone NAAQS in 2006. See id at TS-28. UBAQS also predicts that in 2012 this area will certainly violate the pending, more restrictive ozone levels, even if 2005 meteorological data is used and that this area would have violated the new standards in 2005. See id. At TS-25 to -26. Far from assuring the public that air quality will be kept at a level supportive of public health and that ozone modeling is unnecessary, UBAQS demonstrates that this area faces significant issues related to ozone and the USFS must prepare ozone dispersion modeling.	The ozone analysis has been revised Table 3-13 added to show the reduction in ozone precursors due to operator committed mitigation measures.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	75	UEC, WG, SUWA, WRA, WWP		AQ	Furthermore, there are numerous indicators that ozone is likely already problematic in the region. For example, a large region in Western Wyoming has been declared a nonattainment area because the region violated the ozone NAAQS in 2008. The South Unit DEIS states that ozone levels in the Piceance Basin in Colorado is hovering around 0.74 ppm, a level right at the current NAAQS limit; something that indicates that the Uinta Basin may have problematic levels of ozone. See South Unit DEIS at 53. The South Unit DEIS acknowledges that ozone is a problem in Sublette County, Wyoming. See id. At 54. Sublette County is located north of the Uinta Basin and it shares many similarities in terms of topography, elevation, and climate. Sublette County serves as a warning that wintertime ozone, in particular, may also be problematic in the project area.The likelihood of high ozone levels in the project area is also consistent with recent modeling prepared for the Western Regional Air Partnership ("WRAP"), which further indicates that large areas of the Rocky Mountain West are projected to exceed and/or violate the ozone NAAQS by 2018. In 2008 presentation given at a WRAP Technical Analysis Meeting in Denver, it was reported that the modeling "predicts exceedence of the 8-hour average ozone standard in much of the southwestern US, mostly in spring."8 In particular, since NAAQS will likely be lowered to some number between 0.60 and 0.70 ppm soon, this area is predicted to violate new NAAQS for ozone. The image below, presented at the WRAP Technical Analysis Meeting, shows areas projected to exceed and/or violate the current and future ozone NAAQS. Under the EPA's proposed ozone NAAQS, areas projected to exceed and/or violate the NAAQS include yellow and green. Importantly, the Uinta Basin is expected to exceed and/or violate the EPA's proposed NAAQS of between 0.060 and 0.070 ppm.In addition, recent scientific studies show that ozone in the Western United States is uniquely influenced by atypical factors. For instance, the National Oceanic and Atmospheric Administration (NOAA) recently completed a study finding that ozone air pollution can be problematic in winter in the Rocky Mountain West. After studying the phenomenon in Western Colorado, NOAA stated in a press release:The NOAA team found ozone was rapidly produced on frigid February days in 2008 when three factors converged: ozone-forming chemicals from the natural gas field, a strong temperature inversion that trapped the chemicals close to the ground, and extensive snow cover, which provided enough reflected sunlight to jump-start the needed chemical reactions. 10NOAA reported, "the problem could be more widespread," explaining: "Rapid production of wintertime ozone is probably occurring in other regions of the western United States, in Canada, and around the world."11 A 2008 Colorado Air Pollution Control Division analysis suggests that many areas Western Colorado could be susceptible to high wintertime ozone levels given the propensity for winter-time inversions and other conditions that favor ozone formation. L2	Comment noted.
010	76	UEC, WG, SUWA, WRA, WWP		AQ	Recently, the EPA entered into a settlement agreement with a number of energy companies in the Uinta Basin that resulted in the installation of two air quality monitors in that region. See, e.g., EPA, News Release, "Utah Natural Gas Producers Agree to Air Emission Reductions, Conservation Practices (Apr. 17, 2009), http://yosemite.epa.gov/opa/admpress.nsf/dOcf6618525a9efb85257359003fb69d/6ae54c04ce823alc8525759b0069d8dc!OpenDocument. The USFS must disclose the results of this monitoring in the Uinta Basin. It is likely that these monitors will provide some indication whether wintertime ozone, for example, may be a problem in this region.	Recent monitoring information added in Section 3.2

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	77	UEC, WG, SUWA, WRA, WWP		AQ	There is also increasing evidence that global warming is affecting ambient ozone concentrations. As the United Nations Environmental Programme (UNEP) notes, global warming is an increasingly significant factor "promote[ing] the formation of surface ozone."13 One of the principle effects of global warming is an increase in the "frequency and intensity of heat waves ."14 As a result of the tendency of global warming to produce longer and hotter summer peak temperatures, the Intergovernmental Panel on Climate Change projects increases in July mean ozone concentrations over the industrialized continents of the northern hemisphere will climb above 0.07 ppm by the year 2100.15 Further, a 2007 study by scientists at Harvard, NASA, and the Argonne National Laboratory specifically reported that global warming is likely to increase maximum eight-hour ozone concentrations by 2-5 parts per billion (0.02-0.05 ppm) over large swaths of the United States, including Utah, by mid-century.16Even EPA has noted the need for federal land management agencies to quantify impacts to ambient ozone concentrations in the area In comments to the Bureau of Land Management (BLM) regarding the West Tavaputs Plateau natural gas development project in Utah, EPA stated that "additional cumulative and project-specific air impact modeling should be completed" to address ozone impacts.17 This project is located just south of the project discussed in the South Unit DEIS. See South Unit DEIS at 47. In comments to BLM regarding expansion of oil and gas drilling and production operations in the Pinedale Anticline Project Area of Wyoming, EPA commended BLM for "using the photochemical grid model, CAMx" in analyzing ozone impacts and noted: "This level of analysis is particularly important given the elevated ozone levels that have been recorded at ambient air monitoring stations neighboring the {project area]."18	Noted. The Forest Service collaborated with the EPA to develop appropriate mitigation measures to minimize ozone impacts.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	78	UEC, WG, SUWA, WRA, WWP		AQ	Despite all this, the USFS made no effort to quantify and assess ozone impacts using readily available modeling methods. Without preparing any modeling whatsoever, the USFS has no basis to conclude that the ozone NAAQS, both current and proposed, will be protected, particularly in light of monitoring data and modeling results that utterly refute this finding. The reason the USFS apparently failed to model ozone impacts is based on discussions with the EPA. See South Unit DEIS at 70. While the EPA's recommendations could be helpful in different circumstances, it is unclear how this recommendation supports entirely foregoing an ozone impact analysis. As mentioned above, no ozone analysis has ever been conducted by a federal agency for this region and multiple factors indicate that ozone may be an issue of concern here. Given that the USFS is required to analyze and assess ozone impacts under NEPA, as well as meet its substantive duties under the Ashley National Forest LRMP and USFS planning regulations to protect federal air quality standards, the agency cannot simply ignore the issue, particularly when violations and exceedances have been predicted to occur in this region and may already be occurring (based on new monitoring that should be included in this analysis). A recent federal court decision indicates that the USFS must model ozone. In Southern Utah Wilderness Alliance v. Allred, the Federal District Court for the District of Columbia issued a temporary restraining order against the BLM—including the Vernal Field Office of the BLM, which manages land surround the project area—preventing the issuance of certain oil and gas leases for a failure to model ozone pollution that would result from oil and gas development. Memorandum Order, No. 08-2187 (Jan. 17, 2009) (See attached, Exhibit 2). This order applied to all BLM lands in the Uinta Basin. It is difficult to understand how the USFS's South Unit DEIS could evade a similar order from a federal court since it also ignores ozone pollution and refuses to prepare dispersion modeling. Although we understand that the USFS may have some inability to control emissions of ozone forming pollutants, the agency at least has a duty to understand to what degree any potential oil and gas development on the Ashley National Forest will contribute to ozone concentrations above the NAAQS and to take steps to minimize or eliminate altogether this contribution. To that end, we request the USFS prepare a quantitative analysis of ozone impacts, using either CAMx or CMAQ, two EPA-approved modeling methods, to ensure that the current ozone NAAQS of 0.75 ppm and the proposed NAAQS, which is slated to be finalized in August of 2010, will be protected.	Following thorough consultation with state and federal agencies including EPA, Photochemical modeling was considered but not selected as an analysis tool for this EIS. However, since ozone is a concern, a conservative and preemptive mitigation and monitoring approach was selected in tandem with qualitative analysis. The EPA was intimately involved in assisting the USFS in developing the details of this approach to ensure it met their satisfaction.
010	79	UEC, WG, SUWA, WRA, WWP		AQ	Cumulative Ozone Impacts Are Not Accurately Assessed.As discussed above, there is no cumulative impacts analysis for ozone pollution in the region. The USFS has no support for any assertion that ozone is not a problem in the region and the myriad number of oil and gas projects underway and planned for the Uinta Basin will not result in exceedances of ozone NAAQS and will protect public health. As the UBAQS analysis indicates, this region is likely to face a serious ozone problem. The USFS must undertake a regional ozone analysis.	Noted.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	80	UEC, WG, SUWA, WRA, WWP		AQ	IV. The DEIS Does not Address the New Nitrogen Dioxide National Ambient Air Quality Standards The DEIS does not address the potentially significant impacts to the current NAAQS for nitrogen dioxide. On February 9, 2010, the EPA finalized revisions to the nitrogen dioxide NAAQS, supplementing the current annual standard of 53 ppb with a 1-hour standard of 100 ppb.19 These NAAQS became effective on April 12, 2010. The South Unit DEIS must address these revisions and ensure that nitrogen dioxide impacts on an hourly basis are assessed and limited appropriately.	NAAQs have been updated in the EIS
010	81	UEC, WG, SUWA, WRA, WWP		AQ	V. The South Unit DEIS Does Not Ensure That Air Quality Related Values in the High Uintas Wilderness Area Will Be Protected. The USFS is required to protect the air quality related values of the High Uintas Wilderness Area. See Ashley National Forest, Forest Plan for Land and Resource Management Plan IV-42 (1986) (committing to "[p]reserve and protect air quality related values within the ... High Uintas Wilderness"). However, the South Unit DEIS does not disclose this obligation or explain how those air quality related values will be protected. The USFS must include such a discussion and analysis.	See detailed AQRV impacts analysis in the Air Quality Technical Support Document, included in Appendix C in the FEIS.
010	82	UEC, WG, SUWA, WRA, WWP		AQ	VI. The South Unit DEIS Lacks Adequate Cumulative Impacts Analysis for Air Quality. As with ozone, the South Unit DEIS has failed to consider the cumulative impacts from the South Unit DEIS project combined will all other projects underway in the Uinta Basin and those projects that are reasonably foreseeable. Although the South Unit DEIS acknowledges a large number of development projects in the region that are currently taking place or that are planned, it does not include those projects in a cumulative impacts air quality analysis. See South Unit DEIS at 44-47. The South Unit DEIS includes a near-field and far-field analysis but this is focused on emissions from this project alone and from other large industrial sources but not from any of the other oil and gas projects in the region. See id. At H-3, H-10 to -11, H-22 (listing emissions of focus as those from the project and from industrial sources). This oversight is significant considering the large numbers of wells and projects planned for the region. See id. At 44-47. The USFS must prepare a cumulative impacts analysis that consider pollution from other oil and gas projects in the region, projects that the South Unit DEIS already lists.	Industrial sources and oil and gas wells permitted within a defined time frame (January 1, 2001 through December 31, 2007) through state air quality regulatory agencies and state oil and gas permitting agencies were first researched. The subset of these sources which had begun operation as of the inventory end-date was classified as state permitted sources, and those not yet in operation were classified as RFFA. Also included in the regional inventory were industrial sources proposed under NEPA in the states of Wyoming, Utah, and Colorado. The developed portions of these projects were assumed to be either included in monitored ambient background or included in the state-permitted source inventory. The undeveloped portions of projects proposed under NEPA were classified as RFD. RFD was defined as 1) the NEPA-authorized but not yet developed portions of Wyoming and Colorado NEPA projects, and 2) not yet authorized NEPA projects for which air quality analyses were in progress and for which emissions had been quantified (See Table 5 of the Air Quality Technical Support Document, included in Appendix C of the FEIS).

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	83	UEC, WG, SUWA, WRA, WWP		AQ	VII. The USFS Must Assess the Effectiveness of Any Air Quality Mitigation Measures The USFS asserts that it will address any potentially significant air quality impacts through the proposed air quality mitigation measures listed on pages 31-33 of the SOUTH UNIT DEIS. These measures are laudable. However the USFS has not provided sufficient information and analysis to demonstrate that these measures will be consistently applied and will effectively mitigate emissions so as to ensure protection of all federal and state air quality standards and air quality related values in the High Uintas Wilderness Area. Of particular concern is that it is unclear how the proposed mitigation measures will be implemented and enforced. Although we agree that the USFS has the authority, indeed the affirmative duty, to reduce air quality impacts, the agency has not entirely agreed with this position. In some instances, the USFS has asserted that air quality is not even within the agency's scope of authority, instead falling under the auspices of states and the U.S. Environmental Protection Agency. As discussed earlier, such a position is not supported, both by the agency's planning regulations and the Ashley National Forest LRMP. Even if the USFS agrees in this case that it has the authority to implement the proposed mitigation measures, we request the agency explain how the measures will be enforced. Will the USFS require companies to obtain permits from the State of Utah? Will the USFS require reporting to assure that the specified emissions reductions will be achieved? How will the USFS monitor compliance? More information and analysis is needed to support the agency's assertion that the proposed mitigation measures will effectively address the potentially significant air quality impacts of the proposed development. We are further concerned in light of the USFS's statement that a reduction in Nox and VOCs "would result in a reduction in ozone levels." SOUTH UNIT DEIS at 70. Although we generally agree with this statement, what is disconcerting is that the USFS's own analysis does not demonstrate that the proposed mitigation measures will actually lead to an overall reduction in Nox and VOCs. In fact, the DEIS and air quality technical support document indicate that emissions of NO„ and VOCs will increase as a result of the proposed action, even with the proposed mitigation measures. Thus, there is no support for the USFS's assertion that any reduction in ozone will occur as a result of the project. This is particularly of concern in light of the previously referenced modeling that indicates large portions of the region are likely violating and/or will violate the ozone NAAQS. The USFS cannot blindly rely on the proposed mitigation measures to ensure full protection of air quality standard without demonstrating that the mitigation measures will be effective. The DEIS falls short in this regard. To this end, we request the USFS consider an additional mitigation measure as an alternative. We request the agency analyze in detail and adopt a mitigation measure that caps annual VOC and Nox emissions on the Ashley National Forest at current levels. This mitigation measure should be adopted in conjunction with the other mitigation measures to ensure that, above all, no net increase in emissions occurs. Such a measure will ensure that emissions are either offset, or that development occurs in a phased manner to ensure that emissions do not rise and jeopardize compliance with state and federal air quality standards. We request the agency analyze in detail this alternative mitigation measure pursuant to its duty to consider a range of reasonable alternatives under NEPA.	Effectiveness of mitigation measures assessed in Table 3-13. Analysis revised.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	84	UEC, WG, SUWA, WRA, WWP		AQ	The South Unit DEIS Indicates That Project Modifications Will Be Necessary in Class II Areas. Based on the analysis contained in the South Unit DEIS, the USFS must modify the proposed plan to prevent the exceedances of federal air quality standards in Class II areas (the entire project area). It must also modify the project to limit PM2.5 and the larger particulate matter, PM10, pollution. The entire State of Utah is designated as a Class II area, with the exception of five national parks. Utah State Implementation Plan, Section VIII, Prevention of Significant Deterioration 2 (Mar. 8, 2006), available athttp://www.airquality.utah.gov/Planning/SIP/SIPPDF/SecVIII-PSD.pdf. The entire project area is Class II airshed.The South Unit DEIS predicts that construction activities will lead to an increase in the 24-hour average maximum value of PM2.5 of11.82 ug/m3 in the project area. South Unit DEIS at H-17. The proposed prevention of significant deterioration (PSD) increment limit for this pollutant over this averaging time is 9 ug/m3. Id. At H-47. This standard will likely be implemented before this project is approved or completed. See EPA, "Prevention of Significant Deterioration for PM2.5 — Increments, Significant Impact Levels and Significant Monitoring Concentrations http://yosemite.epa.gov/opei/RuleGate.nsf/byRIN/2060-A024 (Feb. 15, 2010) (projecting that this rule will be issued in June 2010). Since the project area is a Class II area this project will result in levels of PM2.5 that violate a federal air quality standard that is likely to be implemented soon.Furthermore, the modeled 24-hour average maximum value concentrations of PM10 from construction activities will violate current PSD increment limits. The current PSD increment limit for this pollutant is 30 µg/m3; the South Unit DEIS modeling predicts that construction will result in concentrations of 35 06 .if/m3 in the project area. See South Unit DEIS at H-17, H-47. The predicted levels of annual PM10 from construction activities are also likely to result in exceedances of PSD increment limits. The annual PSD increment limit for this pollutant is 17 µg/m3; however, the South Unit DEIS modeling predicts that production will result in concentration increases of 22.68 1g/m3 in the project area. See id.The USFS must modify this project because as it currently stands it will exceed PSD increment limits for both fine and coarse particulate matter.	Increments are not NAAQS. Increment is a term used in major source permitting and is related to development of State Implementation Plans and the PSD major source permitting process. "Violation" of increment is only relevant in these contexts. When an increment is completely consumed (as defined by the CAA and implementing regulations), no new major stationary sources or modifications (as defined by the CAA and implementing regulations) can be constructed without some form of offsets. The FS includes a comparison to PSD increments in air quality sections of NEPA documents for informational purposes only, and does so because the US EPA and some state regulatory agencies, and other federal agencies find it helpful to get a rough estimate. FS NEPA analyses are not regulatory increment analyses, they do not replace such analyses, and they should not be interpreted as indicative of actual increment consumption - which is only relevant in state planning and permitting contexts.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	85	UEC, WG, SUWA, WRA, WWP		AQ	The South Unit DEIS Failed to Inventory Emissions and Model Pollution Generated by Off-Road Vehicles Traveling on Designated Routes as Part of Its Cumulative Analysis. The South Unit DEIS fails to recognize that recreational activities such as all-terrain vehicle (ATV) use and snowmobiling can contribute air pollution. This is a significant oversight as ATV use—which includes any sort of motor vehicle use—on designated routes can generate significant amounts of fugitive dust (which is particulate matter pollution, both PM,s and PM10 and tailpipe emissions, Recently, an organization, the Southern Utah Wilderness Alliance, submitted some analysis and commentary to the BLM on a resource management plan that demonstrate the importance of analyzing the contributions from motor vehicle use on designated routes in order to understand cumulative impacts. This analysis and commentary from the Southern Utah Wilderness Alliance showed that a failure to account for emissions from motor vehicles—ATVs—traveling on designated routes would substantially and significantly understate the amount of particulate matter pollution that was likely to be generated by cumulative impacts from activities on federal lands. The emissions inventory submitted to the BLM by the Southern Utah Wilderness Alliance (prepared by Megan Williams, and air quality expert) examined likely fugitive dust emissions from three routes in the BLM's Monticello Field Office planning area. See Megan Williams, Fugitive Dust Inventory – ORV Travel on Unpaved Routes (Oct. 3, 2008) (See attached, Exhibit 3). This emissions inventory was developed using the EPA's guidance on estimating fugitive dust emissions from vehicle travel on unpaved roads. See id. The estimates from this inventory indicate why the USFS must inventory fugitive dust from ATVs in this South Unit DEIS. It also demonstrates how severely inadequate the South Unit DEIS 'S cumulative impacts emissions inventory is because of its failure to inventory fugitive dust from vehicle travel on designated routes and from the mere existence of routes, which are then susceptible to wind erosion. The inventory prepared by Ms. Williams shows that estimated vehicle travel on the Valley of the Gods scenic byway—some sixteen miles of unpaved road—could result in up to 5.6 tons per year of PM2.5 and 55.8 tons per year for PM10. Id This single route alone surpassed what the BLM's Monticello Resource Management Plan projected for yearly emissions of Pmio (thirty-one tons per year) for the entire BLM planning area from all activities. See BLM, Monticello Proposed Resource Management Plan & Final Environmental Impact Statement 4-29 (2008) ("Monticello RMP"), available at http://www.blm.gov/pgdata/etc/medialib/bltn/ut/monticello_fo/ spanning/nnp/frinpO.P .3 3881.File.dat/Chapter%204.pdf Fugitive dust emissions from this route alone would nearly match the BLM's projections in the Monticello Resource Management Plan for PM2.5 (seven tons per year) from all activities. Id. Ms. Williams projected emissions for two other routes in the BLM's Monticello Field Office. See Williams, Fugitive Dust Inventory. These two routes, combined, consist of thirty-eight miles of unpaved surface; they could contribute up to 51.2 tons per year of PM10 and 5.1 tons per year of PM2 5. Id In all, vehicle travel on the three routes analyzed by Ms. Williams could result in up to 107.0 tons per year of PM10 and 10.7 tons per year of PM2 5 from fifty-four miles of unpaved routes. Id These estimates are three times the projected PM10 emissions and nearly one and one-half the projected PM2.5 emissions in the entire proposed plan. Compare id, with Monticello RMP at 4-29. Considering that the Monticello Resource Management designated 2,800 miles of unpaved routes in the planning area, it is certain that the BLM emissions inventory substantially understated the true impacts from the activities permitted and envisioned in that plan. If one were to extrapolate these.	No ATV use will be permitted on newly constructed project access roads and ATV use on existing roads within the project area is fairly limited.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
002	3	Wasatch County	Draper	COMP	The Secretary of Agriculture under 16 USC Sections 1604(a) shall develop, maintain, and, as appropriate, revise land and resource management plans for units of the National Forest System, coordinated with the land and resource management planning processes of State and local governments and other Federal agencies.Wasatch County General Plan provides for Energy and Mineral Resources as follows: "The oil and gas industry is a significant economic factor in Wasatch county. Leasing in the Strawberry Valley is associated with other known oil and gas fields in the State (including those associated with Duchesne County). As a result, most of the Strawberry Valley has been leased. Some 109,381.58 acres are covered with 49 pending and active leases located in Wasatch County. The oil and gas industry provides employment and economic opportunity and has the prospect to accounts for a significant percentage of the County's tax base. Historically, much of this activity has taken place on private land. Trends since the late 1980's have emphasized development of oil and gas on public lands. Access to public lands is critical to the development of energy and mineral resources."	Noted.
002	9	Wasatch County	Draper	COMP	f. all permits and applications must be processed on a timely basis, in accordance with the Onshore Oil and Gas Order Number 1. Procedures and required contents of of application must be provided by the applicant at the time of application.	Noted.
004	1	U.S. Department of Interior, Office of Environment	Stewart	COMP	As a cooperating agency with jurisdiction by law, the BLM intends to adopt the Environmental Impact Statement (EIS) for the South Unit Oil and Gas Development, Ashley National Forest, without recirculation in accordance with 40 CFR 1506.3(c). Their specific comments and suggestions for this EIS are included below. The BLM will issue its own Record of Decision (ROD) for resources under its control in conjunction with the Forest Service's Record of Decision. If the FEIS does not meet BLM's requirements, the ROD may be postponed until supplemental analysis is completed.	Noted.
004	2	U.S. Department of Interior, Office of Environment	Stewart	COMP	The BLM was verbally invited to be a cooperating agency (CA) early in the process and has participated with the Forest Service (FS) as a CA in the preparation of the Draft EIS. BLM is specifically identified as a CA on page 2 of the DEIS. However, a Memorandum of Understanding (MOU) for this project was never provided to the BLM for signature. Because BLM has jurisdiction by law for oil and gas lease administration beneath lands administered by the Forest Service through 36 Code of Federal Regulations (CFR) 228.5(d); 43 CFR 46.225(d) encourages the BLM to enter into a MOU to identify roles and responsibilities, and the National MOU between the USFS and BLM for Oil and Gas Leasing and Operations, dated April 14, 2006 calls for a more specific MOU if appropriate. The BLM requests the FS as the lead agency develop a MOU that clarifies BLM's role in the EIS process.	There is now a project-specific MOU in place.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	4	U.S. Department of Interior, Office of Environment	Stewart	COMP	Section 1.2: The DEIS is not clear regarding the BLM's role in the review and approval of site-specific APDs that may result should one of the action alternatives be selected in the ROD. This role should be clarified in section 1.2. The BLM's role is to assist in the review of site-specific APDs, especially the downhole portion, to determine adequacy, and to assist in the development of Conditions of Approval (COAs), Best Management Practices (BMPs), mitigation measures, and monitoring requirements to ensure responsible development of the subject federal oil and gas leases.	Change made in Section 1.5 Decision Making Framework.
004	5	U.S. Department of Interior, Office of Environment	Stewart	COMP	Section 1.3: This section should also describe the BLM's purpose and need. The purpose and need for BLM action is to, in conjunction with the Forest Service, respond to the formal Master Development Plan (MDP) from the Operator and to evaluate the impacts in accordance with NEPA.	Change made
004	6	U.S. Department of Interior, Office of Environment	Stewart	COMP	Section 1.5: This section should also explain the BLM's decision framework. The BLM, in conjunction with the Forest Service, will also decide whether to allow development to occur under one of the action alternatives. The BLM will also have a role in determining what COAs, BMPs, mitigation measures, and monitoring will be needed to ensure responsible development of the subject federal oil and gas leases.	Change made
004	7	U.S. Department of Interior, Office of Environment	Stewart	COMP	Page 6, Lines 5-6: It is stated that project decisions will be documented in a ROD signed by the FS responsible officials, and will apply to federal surface estate as well as federal mineral estate in the project area. This is incorrect. The FS decision will apply to surface operations only. The following should be added: "A separate decision will be signed by the BLM, which will apply only to the federal mineral estate. This separate decision may be included in the FS's ROD or a separate ROD prepared by the BLM."	Change made.
004	8	U.S. Department of Interior, Office of Environment	Stewart	COMP	Page 6, lines 9-16: At the end of the paragraph please insert a statement that the BLM will assist in the downhole portion of the APD review as required by law.	Change made.
004	9	U.S. Department of Interior, Office of Environment	Stewart	COMP	Page 7, lines 1-4: Please clarify the paragraph by adding a statement that the FS takes the lead in preparing the environmental documents for actions on FS lands, and the BLM assists as appropriate.	Change made.
004	10	U.S. Department of Interior, Office of Environment	Stewart	COMP	Page 7, lines 16 through 19: Please clarify the paragraph by replacing "federal lands" with "Forest Service-administered lands". In addition, add the Federal Land Policy and Management Act of 1976 (FLPMA), as amended as another authority for the issuance of road and pipeline ROWs that may be applicable.	Changes made.
005	7	Duchesne County Commission	Hyde	COMP	f. All permits and applications must be processed on a timely basis, in accordance with Onshore Oil and Gas Order Number 1. Procedures and required contents of application must be provided by the applicant at the time of application.	Noted.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
005	9	Duchesne County Commission	Hyde	COMP	Under FLPMA, federal land management agencies are required to conform their land development decisions with local plans to the maximum extent possible. Duchesne County believes that Alternative 4 is the mechanism to do just that.	Support for the Preferred Alternative noted.
010	6	UEC, WG, SUWA, WRA, WWP		COMP	Had the Ashley Forest Plan been revised on schedule, various areas would have been reevaluated for wilderness and Research Natural Areas might have been designated. The Forest Plan revision Notice of Intent clearly identifies these decisions as critical features of the revision. The failure to revise the Plan means all of these decisions, as well as other crucial choices, will now wait until the Forest Service has already prejudiced these resources by approving development in the project area. At the same time, the NEPA process involved in the Forest Plan revision addresses numerous other issues of crucial importance to the Forest and the project area, including wilderness suitability, designation of research natural areas, designation of archeological districts, eligibility of wild and scenic rivers, recreation priorities, cumulative impacts, wildlife habitat and much more. The South Unit DEIS ignores these critical issues and the information provided in that process. Moreover, the adoption of any alternative that limits the Forest Service choice in the context of the forest plan revision would be contrary to NEPA. NEPA's mandate is unambiguous on the issue of a mandatory halt to actions during the pendency of this revision process.	The EIS analyzes impacts to potential wilderness and natural areas. The proposed project is consistent with the current Forest Plan.
010	7	UEC, WG, SUWA, WRA, WWP		COMP	Since the 1986 Ashley Forest Plan has expired, and the 1997 WUB EIS and ROD are no longer current and are based on a prediction of minimal oil and gas development, the Forest Service is violating NEPA and NFMA by continuing to rely on these documents in assessing the proposed project. In addition, because the Reform Act requires consistency with the Forest Plan, the agency similarly cannot comply with its obligations under this statute.At this time, the Forest Service has no forest-wide up-to-date understanding of its resources and goals, no reevaluation of those goals, and no analysis or change in direction based on the activities, data collection, and analysis that has occurred over the past 24 years. Therefore, the Forest Service has no notion of what decision, stipulations and mitigation is appropriate to apply to the current proposal. Right now, the Forest Service does not know if, on a forest-wide or site-specific basis, the stipulations of the South Unit leases are sufficient to protect resource values and forest goals. Therefore, before it can properly analyze and approve development in the project area, it must first complete the update of the Ashley Forest Plan.At a minimum, the Forest Service should incorporate into this decision making process all the information it has created in the context of revising its Forest Plan. Moreover, to the extent that the agency has not addressed the issues that are necessarily raised during a forest plan revision process and relevant to the proposed action, it must do so now. Similarly, the Forest Service must also make and apply the decisions that it is required to make in the revision process that are relevant to the proposed action.	The proposed project is consistent with the current Forest Plan.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	43	UEC, WG, SUWA, WRA, WWP		COMP	The South Unit DEIS does not adequately disclose or analyze issues relating to compliance with requirements in the Land and Resource Management Plan (LRMP). To various degrees, each of the action alternatives is in conflict with at least several components of LRMP direction, ranging from Desired Future Conditions (DFC) and Visual quality Objectives (VQO) direction, to objectives and standards and guidelines for affected management area prescriptions.	The EIS includes compliance with the Forest Plan objectives and standards in individual resources sections. Mitigation measures will ensure that DFCs and VQOs are not compromised.
010	48	UEC, WG, SUWA, WRA, WWP		COMP	The proposed 400 wells are also out of the scope of the projected annual outputs, activities and costs prescribed in section IV-E of the LRMP, yet the South Unit DEIS never addresses this issue.	The annual outputs were projections, not prescriptions.
010	3	UEC, WG, SUWA, WRA, WWP		CON	As indicated above, a key requirement of the Reform Act is to ensure that all leases on forest lands include sufficient stipulations that protect surface resources. These lease stipulations were set forth in the 1990 Western Uinta Oil and Gas EIS and ROD and include, in addition to timing limitations in Elk and Deer habitat, Controlled Surface Use (CSU) stipulations in areas occupied by sensitive wildlife species and sensitive plants and where certain visual quality objectives and semi-primitive non-motorized and roadless areas have been identified. In addition, these stipulations provide for No Surface Occupancy (NSO) restraints, inter alia, in areas characterized by geologic hazards, unstable soils, riparian and wetland areas of greater than 40 acres or areas designated as Research Natural Areas. Despite this requirement, the Forest Service has neglected to analyze and apply the relevant lease stipulations which constitute the minimum measures necessary to protect Forest resources. These stipulations apply regardless of the decision on the South Unit proposal ultimately adopted by the Forest Service.	The lease stipulations applicable to Berry's oil and gas lease areas will be applied to all proposed developments for this project (see Section 1.6.3 and Table 1-1 in Appendix A). This EIS is largely programmatic in nature. The noted NSO and CSU stipulations are site-specific, and will be evaluated and applied to specific sites during review of site-specific development proposals.
010	4	UEC, WG, SUWA, WRA, WWP		CON	The WUB EIS, the document in which the Forest Service approved the leasing of the project area, acknowledges that areas in the Forest "of poor reclamation potential would only be covered by SLT [Standard Lease Terms]" and that, as a result "adverse effects on areas of poor reclamation potential would have to be addressed at the APD stage. Table S-2 (Alternative 3). Under the Reform Act, the plan of operations should prohibit development in areas of poor reclamation and should otherwise require stipulations that do not allow adverse effects, but rather "minimize" effects on Forest resources.	Lease stipulations do apply (see Section 1.6.3 and Table 1-1 in Appendix A). Site-specific APDs will comply with lease stipulations.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	33	EPA	Svoboda	CR	Jurisdiction. It appears that the general project location is largely or entirely on National Forest lands within the Uintah Valley part of the Uintah and Ouray Indian (U&O) Reservation, and therefore in Indian country according to applicable case law. Accordingly, the EIS should accurately reflect that the proposed project will be located largely or entirely in Indian country. EPA has not approved the State of Utah or the Ute Indian Tribe to implement federal environmental programs in Indian country. Thus, for all locations on Indian country lands within the U&O Reservation, EPA is the appropriate governmental authority to issue federal environmental permits, conduct inspections, take enforcement actions, and take any other actions pursuant to our statures and authorities. References to UDEQ permits in the document should be revised. Similarly the NHPA consultation discussion should reference consultation with the designated representative of the Ute Indian Tribe along with the SHPO. We note that the BIA has particular expertise as to Indian country questions. You may wish to consult with BIA on the status of the project location.	The NHPA consultation has included and will continue to include designated representatives of the Ute Indian Tribe (see FEIS Section 3.11). The Forest has developed a Programmatic Agreement to fulfill the requirements of Section 106 of the National Historic Preservation Act (NHPA) for actions related to the South Unit Oil and Gas Development. The Programmatic Agreement has been attached to the FEIS as Appendix I and describes the measures the Forest take when impacts to sites cannot be mitigated.
007	34	EPA	Svoboda	CR	The EIS should accurately reflect that the proposed project is largely or entirely located on Indian country lands within the U&O Reservation, and should identify the appropriate permitting agencies consistent with Indian country status. Statements and depictions that should apparently be revised include:-Figure 1-1 (shows Reservation boundary ending at National Forest)-Table 1-1 (apparently inapposite reference to UDEQ permitting, and to Indian country, USA, Inc v Oklahoma Tax Common, 829 F2d 967 (10th Cir 1987) as relevant authority; also, omission of EPA as appropriate permitting authority)3.11.1.18 ("In 1905, President Theodore Roosevelt removed 1,004,285 acres from the reservation and transferred them to the Uinta National Forest" also, "1905, when the South Unit was removed from the reservation…")-3.11.2.8 ("The NHPA also requires the Forest Service to provide the Utah State Historic Preservation Officer (SHPO) an opportunity to comment of the proposal and consult with concerned Native American tribes prior to project implementation.") This language is not wholly consistent with the relevant NHPA regulation at 36 CFR 800.2©(2)(i)(B), which provides that where there is no THPO the agency must consult with a designated tribal representative in addition to the SHPO.-3.15.2.1.2 and 3.15.2.1.3 ("the Uintah and Ouray Indian Reservation boundary to the north")-3.15.2.3.5 (discussion should make clear that "Reservation lands" encompass the "Forest Service-administered public lands.")-Appendix A (Master plan refers only to SHPO consultation and not to consultation with Ute Tribe representative.)	The Forest does overlap the reservation and therefore is in Indian country. The history of the reservation is somewhat complicated, since it was created from restored lands, leaving a checkerboard pattern of jurisdiction (FEIS 3.11.1). Therefore the EIS has been revised to reflect that those lands located within Indian country would require the appropriate EPA federal environmental permits, and the EPA would be the responsible party to conduct inspection, take enforcement actions and any other actions pursuant to EPA statutes and authorities~~.~~ Those lands located on NFS lands not in Indian country would require UDEQ permits (FEIS section 3.2). The FEIS has been revised to say that the NHPA consultation will include designated representatives of the Ute Indian Tribe (see FEIS section 3.11.4). Figure 1-1 was developed to show the location of the project area within the boundary of the ANF, not to depict legal jurisdiction of Reservation boundaries.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	35	EPA	Svoboda	CR	National Historic Preservation ActThe Draft EIS states that the Forest Service will consult with affected Native American tribes regarding impacts to cultural resources, as required by the National Historic Preservation Act. Please state which tribes have been contacted during this process and how these tribes were selected for consultation. (The list in Section 4.1.3 identifies the Northern Ute Indian Tribe and four entities associated with that tribe as participants in scoping. If the Northern Ute Tribe is the only tribe determined to be potentially affected, the EIS should so state. Similarly, throughout the document, these references should be more specific.)	The Forest invited four Native American Tribes to participate during National Historic Preservation Act (NHPA) consultation on the project (The Northern Ute Tribe-Uintah Ouray Reservation, Southern Ute Indian Tribe, Ute Mountain Tribe, and the Hopi Indian Tribe). The Ute Northern Tribe was invited because the South Unit is within their ancestral lands. The Northern Ute Tribe requested that both the Southern Ute Tribe and the Ute Mountain Tribe also be invited to participate. The Hopi Indian Tribe was invited to participate because they have previously indicated their belief that the Hopi have an ancestral connection with the people of the Fremont culture. Of the invited tribes, only the Ute Northern Tribe has indicated an interest in consulting on this specific project. The Forest has developed a Programmatic Agreement (attached as an Appendix to the EIS) to fulfill the requirements of Section 106 of the NHPA and to guide ongoing consultation with Native Indian Tribes (see FEIS section 3.11.2.8 and the Programmatic Agreement in Appendix D).
010	45	UEC, WG, SUWA, WRA, WWP		CR	Similarly, the LRMP standard requiring prevention of any damage to all significant archeological sites is not assured by the analysis in the South Unit DEIS. That is due in part to aspirations to future surveys, which is not sufficient to inform this EIS or to ensure compliance with the rules and NFMA	The Forest has developed a Programmatic Agreement (PA), in consultation with the Advisory Council on Historic Preservation (ACHP), the Utah State Historic Preservation Officer (SHPO), and the Northern Ute Indian Tribe in order to fulfill the requirements of Section 106 of the National Historic Preservation Act (NHPA). The PA specifies the type of identification efforts (cultural surveys) that will be completed prior to the implementation of any site specific actions and outlines the process the Forest will use to avoid, minimize, or mitigate adverse effects to National Register eligible cultural resources. The process outlined in the Programmatic Agreement ensures the Forest will meet the legal requirements of Section 106 of the National Historic Preservation Act (NHPA) as well as the Forest Land and Resource Management Plan and the National Forest Management Act (NFMA). Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA has been attached as an Appendix to the EIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	49	UEC, WG, SUWA, WRA, WWP		CR	Prehistoric and Historic Properties. The Forest Service had recognized that that "direct and/or indirect impacts would occur under all alternatives and correlate directly to the amount (acreage and depth) of surface disturbance in areas that contain surface or subsurface cultural resources." South Unit DEIS at 195. Although it knows that there will be a loss to cultural resources, the agency does not mention any intention to obtain the required comments from the Advisory Council. The South Unit DEIS states that a cultural survey will be conducted prior to ground-disturbing activities. It also states that standard stipulations require the lessees to report and protect cultural resources. However, the existence of the stipulation does not relieve the agency of its obligation, for example, to identify eligible properties before the pending decision is made.	In consultation with the Advisory Council on Historic Preservation (ACHP), the Utah State Historic Preservation Officer (SHPO), and the Northern Ute Indian Tribe the Forest has developed a Programmatic Agreement (PA) to fulfill the requirements of Section 106 of the National Historic Preservation Act (NHPA). The PA specifies the type of identification efforts (cultural surveys) that will be completed prior to the implementation of any site specific actions. Because the Forest anticipates that adverse effects to National Register eligible cultural resources will occur during the project, the PA outlines the process the Forest will use to avoid, minimize, or mitigate adverse effects to these resources. The PA also includes a Monitoring Plan to measure the level and frequency of indirect and cumulative effects in order to evaluate if the requirements of the PA are sufficient to minimize effects to cultural resources. The process outlined in the Programmatic Agreement ensures the Forest will meet the legal requirements of Section 106 of the National Historic Preservation Act (NHPA) as well as the Forest Land and Resource Management Plan and the National Forest Management Act (NFMA). Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA has been attached as Appendix D in the FEIS.
010	50	UEC, WG, SUWA, WRA, WWP		CR	The NHPA also requires the agency to consult with State Historic Preservation Officer (SHPO), Native Americans, and the public before the agency proceeds with undertakings that "may affect" listed or eligible historic properties. 36 CFR 800.2. The agency must provide the public with information about an undertaking and its effect on historic properties and seek public comment and input." Id. At 800.2(d)(2). The purpose of this consultation is to involve the agency and interested parties in the identification of "historic properties potentially affected by the undertaking, assessment of] its effects and [the] seek[ing of] was to avoid, minimize or mitigate any adverse effects on historic properties." 36 CFR 800.1(a). The Forest Service must consult now with affected tribes prior to making a decision on the proposed project.	The Forest has consulted with the Advisory Council on Historic Preservation (ACHP), the Utah State Historic Preservation Officer (SHPO), the Northern Ute Indian Tribe, and the Utah Professional Archaeological Council to develop a Programmatic Agreement (PA) that fulfills the requirements of Section 106 of the National Historic Preservation Act (NHPA). The Forest also invited the Colorado Plateau Archaeological Alliance, the Utah Rock Art Research Association, and the Southern Utah Wilderness Alliance to participate during the NHPA review process, but did not receive a response. The PA outlines the process the Forest will use to avoid, minimize, or mitigate adverse effects to National Register eligible cultural resources. Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA has been attached as Appendix D in the FEIS.
010	51	UEC, WG, SUWA, WRA, WWP		CR	As mentioned elsewhere, the Forest Service based the WUB EIS and ROD on a reasonably foreseeable development scenario that has already been eclipsed on the Ashley Forest, and will certainly be eclipsed by the proposed project. This means that the agency must examine impacts to cultural resources across the forest to determine If the adverse impacts that will result from any development of the project area are appropriate on a forest-wide basis. Said another way, the WUB EIS and ROD are premised upon the assumption that oil and gas wells would be minimal at most. Thus, the current proposal is contrary to a major assumption on which these decision documents are based.	Forest wide effects to cultural resources are reviewed in accordance with the Ashley National Forest Plan, Forest Service Manual Directives, and pursuant to regulations outlined in 36 CFR 800. Effects to cultural resources within the Berry Petroleum Company lease area will be reviewed, evaluated, and documented in accordance with the Berry Petroleum South Unit Oil and Gas Master Development Plan Programmatic Agreement (Agreement # AS-11-00017). The Programmatic Agreement takes into account the direct effects of the project activities on Historic Properties as well as monitors the potential indirect and cumulative effects of project activities on Historic Properties. Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA has been attached as Appendix D in the FEIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	52	UEC, WG, SUWA, WRA, WWP		CR	Finally, as the Forest Service makes clear, very little of the Forest and very little of the project areas have been surveyed for archaeological and historical sites. By the same token the Forest Service does not know whether identified sites are eligible under the National Register of Historic Places (NRHP). Failure to identify the affected cultural resources and evaluate whether these properties are eligible for the National Register violates 36 CFR 800.4(b) and (c). Because it has not adequately identified resources and determined their eligibility, and because it has based its analysis on unrealistically limited development, the agency has not properly assessed the possible effects of the leasing, 36 CFR 800.4(d), 800.5(a), and has not adequately determined whether any effects would be adverse. 36 CFR 800.5. This, in turn, has prevented the Forest Service from taking subsequent steps in the consultation process such as identifying avoidance or mitigation measures. At the same time, the Forest Service has no data or analysis to provide a basis for its claim that most of these sites will be avoided. Without such an analysis, the agency has violated NEPA and the NHPA because it cannot accurately determine the likely impacts of the project on cultural resources.	The Forest is complying with the requirements of the National Historic Preservation Act (NHPA) and 36 CFR 800 through the development and implementation of a Programmatic Agreement (PA) for the project. Discussion of the PA has been added to Section 3.11 of The Final EIS and the entire PA has been attached as Appendix D in the FEIS. The PA provides specific methods for identification efforts (survey), documentation, and National Register evaluations for cultural resources. The PA also specifies the process the Forest will use to avoid, minimize, or mitigate any potential adverse effects to National Register eligible cultural resources as required by 36 CFR 800. The stipulations of the PA and compliance with the NHPA will be accomplished regardless of the selected alternative.
010	53	UEC, WG, SUWA, WRA, WWP		CR	That impacts to cultural sites from development are unavoidable and in violation of the NHPA underscores the need for the Forest Service to enforce its previous prohibition on surface occupancy in stream beds and institute a buffer around these areas, as well as other areas where cultural sites occur in high concentrations. The prevalence of cultural sites in the project area also means that the Forest Service must, under the WUB ROD, the Forest Plan and its statutory duties, prohibit road building in stream corridors.	Mitigation common to all alternatives have been designed to protect riparian areas with buffers that vary between 50 and 150 feet depending on stream type, protect cultural resources through avoidance, minimizing or mitigating adverse effects to eligible cultural sites, and generally limit new road and pipeline construction within buffers zone to perpendicular or near perpendicular crossings of channels (FEIS Chapter 3 sections 3.6, 3.7, 3.9, and 3.11)
010	54	UEC, WG, SUWA, WRA, WWP		CR	Because development of the project area will harm cultural sites, the Forest Service has failed to consider an alternative to the proposed development that will protect cultural resources and ensure compliance with the NHPA. Such an alternative would prohibit development in areas with high concentration of sites.	The Forest is complying with the requirements of the National Historic Preservation Act (NHPA) and 36 CFR 800 through the development and implementation of a Programmatic Agreement (PA) for the project. Discussion of the PA has been added to Section 3.11 of The Final EIS and the entire PA has been attached as Appendix D to the FEIS. The PA provides specific methods for identification efforts (survey), documentation, and National Register evaluations for cultural resources. The PA also specifies the process the Forest will use to avoid, minimize, or mitigate any potential adverse effects to National Register eligible cultural resources as required by 36 CFR 800. The stipulations of the PA and compliance with the NHPA will be accomplished regardless of the selected alternative.
010	55	UEC, WG, SUWA, WRA, WWP		CR	The Forest Service has failed to identify, analyze the effectiveness of, and required mitigation measures designated to protect cultural sites.	The Forest has developed a Programmatic Agreement (PA) that specifies the process the Forest will use to avoid, minimize, or mitigate any potential adverse effects to National Register eligible cultural resources as required by 36 CFR 800. Because the effects of site specific action on cultural resources will not be known until the site specific actions have been proposed, the Forest has developed the PA to guide how the Forest will resolve adverse effects to National Register eligible cultural resources. Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA has been attached as an Appendix to the EIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	56	UEC, WG, SUWA, WRA, WWP		CR	-The Forest Service has failed to identify, analyze the effectiveness of, and require avoidance of cultural sites.	The Forest has developed a Programmatic Agreement (PA) that specifies the process the Forest will use to identify, document, and evaluate cultural resource sites. The PA also outlines how the Forest will avoid, minimize, or mitigate adverse effects to National Register eligible cultural resources as required by 36 CFR 800. A component of the PA will be a monitoring plan to provide information on the effectiveness of the avoidance procedures of the project. Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA has been attached as an Appendix to the EIS.
010	57	UEC, WG, SUWA, WRA, WWP		CR	-The Forest Service must acknowledge the impact of soil erosion, including water and wind erosion, on cultural sites and develop and require measures to avoid and mitigate this adverse impact. This analysis must include cumulative impacts from existing activities.	The Forest has developed a Programmatic Agreement (PA) that specifies the process the Forest will use to avoid, minimize, or mitigate any potential adverse effects to National Register eligible cultural resources as required by 36 CFR 800. Because the effects of site specific action on cultural resources will not be known until the site specific actions have been proposed, the Forest has developed the PA to guide how the Forest will resolve adverse effects to National Register eligible cultural resources. Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA has been attached as Appendix D in the FEIS.
010	58	UEC, WG, SUWA, WRA, WWP		CR	-The South Unit DEIS needs to quantify the engineering and construction costs associated with complying with the NHPA and reducing soil erosion t mitigate impacts on cultural sites.	The South Unit EIS is a programmatic document that gives broad guidance for site specific actions. The engineering and construction costs to mitigate impacts on cultural sites will be evaluated and addressed for each site specific action on a case by case basis.
010	59	UEC, WG, SUWA, WRA, WWP		CR	-The Forest Service did not analyze the impact on cultural sites of the air pollution generated by the proposed project and alternatives.	An initial cultural resource overview of the project area indicates that the type of sites present on the south Unit would not be adversely affected by air quality. The south unit project area is quite different from canyons to the south (such as Nine Mile Canyon) and does not have geological strata that make good canvasses for rock art. The limited rock art found within the South Unit will be avoided based on Forest Cultural Resource Protocols outlined in the Programmatic Agreement developed for this project. Buried cultural resources are typically not affected by air quality, but the Forest has developed a Monitoring Program to evaluate and assess potential cumulative and indirect effects of the project on cultural resources. Discussion of the PA has been added to Section 3.11 of the Final EIS and the entire PA (including Monitoring Plan) has been attached as an Appendix to the EIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	12	U.S. Department of Interior, Office of Environment	Stewart	CUM	Table 3-1: The following BLM documents were identified as being final documents. However, these documents should be identified as “under preparation” because as of the date of this comment letter, they have not yet been finalized. O Little Canyon EA, o Big Pack Project EA, o Riverbend EA. In addition, the “Greater National Buttes EIS” should be corrected to “Greater Natural Buttes EIS”	Table 3-1 has been updated based on the BLM NEPA website. http://www.blm.gov/ut/st/en/fo/vernal/planning/nepa_.html. Made change to "Greater Natural Buttes EIS".
006	26	State of Utah, Public Lands Policy Coordination	Harja	CUM	The Reasonable Foreseeable Development Scenario (RFDS) analysis by Engler and Cather (2007) is not included as an appendix. Since the RFDS is not a formal publication that is widely available to the public, it should be included as part of the final EIS to allow for transparent public review of the analysis that went into formulating the EIS.	This document is available by request and is on file with Ashley National Forest, Vernal, UT.
010	5	UEC, WG, SUWA, WRA, WWP		DP	An underlying assumption throughout the South Unit DEIS is that the leaseholder has contractual rights that trump public values about resource protection. However, under the Reform Act, it is plain that protection of resource values takes precedent over development rights as long as the leaseholder is able to exercise its contractual rights. This means that the lessee must be able to develop at lease one location on each lease.Many of the leases in the project area already contain at least one producing well. The leaseholder in these situations is currently deriving financial benefit from the lease. Therefore, the Forest Service is free to and must analyze and consider alternatives that restrict development to one installation per lease. Where the protection of Forest resources, the avoidance of riparian areas, wetland and zones of unstable soils and compliance with the Clean Water Act and NHPA so require, the Forest Service must limit development to this extent.	See the Western Uinta Basin Leasing EIS for lease agreements. Lease stipulations are included in the South Unit EIS in Table 1-1 of Appendix A, and will be applied to the proposed project developments during review of site-specific proposals. Federal mineral leases do not stipulate one location or development per lease, but allow up to one location per 40 acres, as was analyzed in the EIS under the Proposed Action. Lease stipulations and mitigations for protection of riparian areas, areas with unstable soils, and various resources have already been included within the EIS.
006	28	State of Utah, Public Lands Policy Coordination	Harja	EDT	Table 1.1 is difficult to follow due to inadequate formatting	The table was updated and moved from the FEIS to the project record
006	32	State of Utah, Public Lands Policy Coordination	Harja	EDT	Subsection 3.3.1.4, Page 79: line 11, the word "in" should be changed to "from" so that the sentence reads "production of almost 365 million barrels of oil (MBO) occurred from the Green River system" line 32, "the Mancos Shale" should be inserted after "the Mesaverde Group," since the Mancos is productive elsewhere in the Uinta Basin and is a potential reservoir beneath the South Unit area. Line 39, the word in parentheses at the end of the line (Cotlon) is misspelled and should be "Colton." line 42, this line should be modified to read "Formation and Mancos Shale, although higher risk, have also become targets in the Uinta Basin, but"	Changes made.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	33	State of Utah, Public Lands Policy Coordination	Harja	EDT	Subsection 3.16.2.2: Page 256, line 10, "Table 3-76" should be changed to read "Table 3-77". Page 256, line 12, "(Table 3-77)" should be changed to read "(Table 3-78)". Page 257, line 14, the word "likely" should be dropped since the project would contribute to a positive impact on tax revenues. Page 258, Table 3-80, the note at the end of the table incorrectly refers to Table 3-78, when Table 3-79 has the data on costs per well.	Changes made.
006	34	State of Utah, Public Lands Policy Coordination	Harja	EDT	Chapter 5, References, page 279. line 16, the last name of the third author should be "Cashion". Line 33, the reference by Engler and Cather should include the number of pages in the report if this report is not included as an appendix.	Changed to Cashion
007	36	EPA	Svoboda	GCC	EPA recommends that EISs include an analysis and disclosure regarding climate change. We generally suggest the following four step approach.1. Discuss projected regional climate change impacts relevant to the action area, consider any future needs and capacity of the proposed action to adapt to projected climate change effects, and if appropriate, identify effects from the action that may be exacerbated by projected climate change. 2. Characterize and quantify the expected annual and total project lifetime cumulative GHGs. 3. Briefly discuss the link between GHGs and climate change and the potential impact of climate change. 4. Discuss potential means to mitigate project-related emissions.	Climate change and GHG emissions are discussed in Section 3.2.
007	37	EPA	Svoboda	GCC	EPA appreciates the discussion of global concerns regarding climate change in the Draft EIS and the disclosure of expected yearly CO2 Equivalent emissions. We are particularly pleased that expected annual GHG emissions have been put in a relevant context in Table 3-14 by comparing to statewide and national emissions. However, we recommend that expected total project lifetime cumulative emissions of GHGs be quantified and included in the Final EIS and placed in a relevant context. Further, we recommend that a discussion of potential means to mitigate project-related emissions be included in the Final EIS. The potential impacts of climate change on the proposed project should also be addressed, as described in 1 above, particularly if any potential impacts from the proposed action may be exacerbated by climate change	Your recommendations have been noted, and a variety of air quality mitigations have been added to this project, to minimize project-related air quality emissions. Expected cumulative emissions of GHGs over the life of the project have not been calculated for this project, because of uncertainties regarding the productive lifetime for individual wells, and also the total number of wells to be drilled over the life of the project.
002	4	Wasatch County	Draper	LAU	It is the position of Wasatch County that a. Access to public lands for mineral development must be maintained and increased in an environmentally sound basis to enhance the economic interest of county citizens and government.	Noted. See section 3.14 transportation for maintenance and transportation plans related to this project.
002	5	Wasatch County	Draper	LAU	b. Mineral exploration and development are consistent with the multiple use philosophy for management of public lands. These activities constitute a temporary use of the land that will not impair its use for other purposes over the long term. All oil and mineral exploration activities shall comply with appropriate laws and regulations and shall be conducted in an environmentally sound process, including heli-drilling where appropriate.	See Table 1-1 for ANF LRMP management area designations and uses within the project area, section 2-2 for description of long-term and short-term impacts by alternative, and section 1.6 for the regulatory setting.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
002	6	Wasatch County	Draper	LAU	c. Encourage exploration of energy and minerals on public land to ensure that our future energy needs and resource management opportunities are considered. Agencies shall plan, fund, and encourage by policy and management decisions relative to energy resources.	Noted: See Chapter 1 Purpose and Need for Action.
002	7	Wasatch County	Draper	LAU	d. All management plans must address and analyze the possibility for the development of minerals where there is a reasonable expectation of their occurrence.	Noted: see Table 1-1 for ANF LRMP management area designations and uses within the project area.
002	8	Wasatch County	Draper	LAU	e. After environmental analysis, and as provided for in the governing resource management plan, all tracts will be available and offered for lease or opened to be claimed as provided by law. Wasatch County recognizes that while all Federal administered land within the county is currently available for lease, decisions are made regarding oil and gas leases through the lands use planning process. Alternatives identify areas where leasing may occur with standard lease terms, timing and controlled surface use stipulations or no surface occupancy. Additionally, some areas may be considered for no leasing in the future.	Noted: See section 1.5 Decision Framework
005	13	Duchesne County Commission	Hyde	LAU	Section 3.13 of the DEIS addresses potential wilderness areas. There are four potential wilderness areas within the project boundaries; Cottonwood, Sowers Canyon East, Nutter Canyon and Alkali Canyon. What the DEIS does not appear to mention is that all four of these areas were rated "low" in the "availability" category due to the presence of valid, existing oil and gas leases and "moderate" in terms of capability and need (see Page 7 of the 2008 Draft of the Potential Wilderness Report). We remind you that Duchesne County is opposed to the establishment of additional wilderness areas in the county (see general plan policy below). Wilderness Designations Duchesne County is host to approximately 250,000 acres of federally designated wilderness, which comprises twelve percent of the county's land area. Land features include vistas of high barren peaks, dense lodge pole forests, rugged canyon lands, lakes and streams, and significant watershed areas. The County has previously made a disproportionate contribution to the nation's wilderness system. Although Duchesne County acknowledges the values of the High Uintah Wilderness Area, use is highly restricted and does not provide the desired wilderness experience for the vast majority of citizens. Wilderness designation is inconsistent with the philosophy of multiple use and sustained yield and adversely affects the County's economy in terms of the grazing, tourism, and timber industries and water resources. It is the position of Duchesne County that: a. Wilderness designation is inconsistent with the multiple use mandate. b. Additional wilderness designation shall be opposed. c. Such designations shall provide access for reservoirs, maintenance of irrigation facilities, fire, weed and pest control. d. Valid existing rights are to be protected in wilderness areas. e. Proper monitoring of the affect of a wilderness area on the community and economic stability of the county shall be required.	Comments noted. Wilderness designation and inventory for lands with wilderness potential are outside the scope of this analysis. Designating Wilderness is a congressional action. Wilderness potential using wilderness attributes is an analysis required in NEPA to disclose the trade-offs of alternative land uses. Since lands meeting those criteria were inventoried in 2005, the inventory is used to evaluate wilderness attributes. The EIS section has been re-written to better reflect impacts to wilderness attributes and potential.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
005	18	Duchesne County Commission	Hyde	LAU	Enclosed is a map that shows the location of existing oil and gas wells in Duchesne County. The map demonstrates that the Bureau of Land Management and the Bureau of Indian Affairs have been progressive in allowing access to the energy resources under the surface they control. These resources extend beyond jurisdictional boundaries. It is time for the Forest Service to allow for valid, existing energy leases to be developed on the South Unit of the Ashley National Forest. The draft DEIS demonstrates that Berry Petroleum's leased area can be developed under certain stipulations and mitigation measures in an environmentally responsible way. We look forward to the receipt of the Final DEIS and Record of Decision allowing this project to move forward.	Noted.
002	10	Wasatch County	Draper	MIT	g. Development of the solid, fluid, and gaseous mineral resources of the state should be encouraged. The waste of fluid and gaseous minerals within developed areas should be prohibited. Requirements to mitigate or reclaim mineral development projects should be based on credible evidence of significant impacts to natural or cultural resources.	Noted.
005	8	Duchesne County Commission	Hyde	MIT	g. Development of the solid, fluid, and gaseous mineral resources of the state should be encouraged. The waste of fluid and gaseous minerals within developed areas should be prohibited. Requirements to mitigate or reclaim mineral development projects should be based on credible evidence of significant impacts to natural or cultural resources.	Noted.
006	9	State of Utah, Public Lands Policy Coordination	Harja	MIT	UDWR supports the recommendation in Section 2.2.2 for elk, i.e. no drilling or construction activities may occur between November 15 and April 30 within the areas identified as crucial winter range. UDWR also recommends that, where possible, wells and related infrastructure be constructed in forested areas and include a forested buffer from any sagebrush, mountain brush and grassy openings. These openings provide essential forage for many species and are crucially important to wildlife.	Wildlife openings will be avoided, where possible, on a site-specific basis. Mitigation for sage grouse requires that within 4 miles of a lek, in openings of the pinyon/juniper (chained or natural openings in pinyon/juniper belt), well pads should be located as close to the edge of the opening as possible (section 3.9.2). This would help protect opening for elk and deer.
006	10	State of Utah, Public Lands Policy Coordination	Harja	MIT	UDWR also recommends the piping of produced fluids to centralized collection facilities to reduce the disturbance related to truck traffic.	Centralized facilities are an additional BMP analyzed for Alternative 3. Produced natural gas would be piped to centralized collection facilities as recommended. Crude oil within the project area is too viscous to pipe over long distances, and must be trucked from individual well pads.
006	12	State of Utah, Public Lands Policy Coordination	Harja	MIT	Additionally, UDWR recommends that areas vegetated with sagebrush and grasses be avoided as potential sites for the construction of well pads, pipelines, roads, compressor station and other related infrastructure.	Wildlife openings will be avoided, where possible, on a site-specific basis during review of APDs.
006	13	State of Utah, Public Lands Policy Coordination	Harja	MIT	UDWR also recommends seasonal closures for drilling and all construction related activities in all areas identified as crucial mule deer winter range from December 1 through April 15.	See sections 2-2 and 3.9. for design elements/mitigation which apply to all action alternatives including " Well pad and road construction, road upgrades, and drilling operations would not be conducted between November 15 and April 30 to protect elk winter range" (which overlaps mule deer winter range).

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	16	State of Utah, Public Lands Policy Coordination	Harja	MIT	Surface disturbance should be mitigated through the completion of habitat improvement projects approved by UDWR and the Ashley national forest. This mitigation should be completed at a ratio which balances direct disturbances to wildlife habitats and also extend to account for indirect impacts from the proposed development. A ratio of one acre directly impacted to four acres restored is recommended and accounts for the admittedly difficult to measure indirect effects. A 1:4 compensatory mitigation ratio has been agreed to by other companies working in other similar areas of Duchesne County. UDWR supports the 1:4 compensatory mitigation ratio as a reasonable balance between completely ignoring indirect effects and spending exorbitant sums trying to scientifically measure the true extent of the indirect effects.	Habitat improvement projects have been occurring in the area for the last 5 years and are expected to continue in the future. Additional restoration projects are currently being planned on the Forest, which will additionally offset impacts.
002	1	Wasatch County	Draper	NEPA	Wasatch County supports NEPA requirements to evaluate a "reasonable range" of alternatives. However, in light of the National Energy Policy, a No Surface Occupancy alternative would be counterproductive to a policy aimed at reducing or eliminating impediments to oil and gas leasing on federally managed lands.	Noted. Please see sections 1.6.3 Consistency with the Western Uinta Basin Oil and Gas Leasing EIS which identified areas of No Surface Occupancy; 2.3 Alternatives Considered but Eliminated from Detailed Study, and 3.5 Soils for further discussion of No Surface Occupancy.
002	2	Wasatch County	Draper	NEPA	Wasatch County supports an Energy Policy to "rationalize permitting for energy production in an environmentally sound manner by directing federal agencies to expedite permits and other federal actions necessary for energy related project approvals on a national basis". We also support the development of a task force, chaired by the Council on Environmental Quality to ensure that federal agencies responsible for permitting energy related facilities are coordinating their efforts. This will ensure that federal agencies set up appropriate mechanisms to coordinate federal, state, tribal, and local government permitting activity in particular regions where increased activity is expected.	Noted.
002	11	Wasatch County	Draper	NEPA	Federal Agencies, under FLPMA, are required to ensure that federal land use plans are consistent with state and local plans to the maximum extent possible (provided the Secretary finds such plans to be consistent with federal law and the purposes of the act). Under NEPA, federal agencies are required to integrate environmental impact statements into state or local planning processes. Statements shall discuss any inconsistency of a proposed action with approved state or local plans or laws (whether or not federally sanctioned). Where an inconsistency exists, the statement should describe the extent to which the federal agency would reconcile its proposed action with the plan or law.	NEPA directs federal agencies to evaluate and disclose inconsistencies between their proposed action and local land use plans and policies (40 CFR 1502.16(c) and 1506.2(d). Consistency with County land use plans was addressed in the FEIS Chapter 1 section 1.6.4.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	43	EPA	Svoboda	RCL	Reclamation Potential. We are concerned that 388 acres (47%) of the soil disturbance associated with the Preferred Alternative will take place in highly erodible soils and/or soils with poor reclamation potential… EPA is pleased that the Preferred Alternative has been designed to reduce surface disturbance. Particularly, reducing the number of well pads by 60% and co-locating all pipelines in access road ROW will lessen the impacts described above and increase reclamation potential. Prohibiting off-road driving in the project area and closure of all new roads to public travel will also aid reclamation efforts. We further recommend that the recommended and proposed mitigation measures listed in the Draft EIS for reduction of impacts related to soils and vegetation disturbance be required of contractors and noted in the ROD. Travel management in the project area should be designed for maximum reduction in soil and vegetation impacts. Access roads and well pads should be sited to avoid highly erodible soils, biological soil crusts, and sensitive vegetation communities whenever possible. Impacts associated with access roads should be reduced to the maximum extent practicable, but utilizing transportation planning to establish proper road location and design, and using primitive two-track roads where possible.	Off-road driving is already prohibited on the Forest and mitigation measures which prohibit public motorized travel on roads constructed for this project are common to all action alternatives. Mitigation designed to minimize impacts to soils and vegetation are listed in Chapter 2 under the applicant-committed mitigation measures as well as the vegetation and soils resources sections.
010	2	UEC, WG, SUWA, WRA, WWP		RCL	Also as required by the Reform Act, the Forest Service must adequately calculate an amount sufficient to fully reclaim and surface resources, including watersheds and cultural resources, damaged by development surface. The agency must require a bond sufficient to cover these expenses. This analysis and requirement must be subject to public notice and comment.	The BLM manages reclamation bonding through the APD process.
006	8	State of Utah, Public Lands Policy Coordination	Harja	REC	The project area is located within the Nine Mile/Anthro elk management unit. This elk herd is managed as a limited-entry hunting unit. Opportunities to hunt elk within the unit are highly prized by the public. Increased activity to oil and gas exploration and production may negatively affect the big game hunting experience within the unit. UDWR encourages the Ashley National Forest to minimize impacts to the Nine Mile/Anthro elk herd and the high quality elk hunting experience it provides for sportsmen.	Mitigation measures designed to minimize impacts to elk herds are listed in the FEIS Chapter 3 section 3.9.
007	20	EPA	Svoboda	RIP	The Draft EIS states that the Sowers Creek will be avoided, and therefore no significant impacts to wetlands or riparian areas are anticipated. EPA recommends that further information regarding commitment to avoidance be included in the EIS. For example, will Sowers Creek be avoided by all facilities, including roads and pipelines, or by well pads only? How wide of an avoidance margin will be required?	Further information regarding commitment to avoidance and mitigations to minimize impacts to Sower Creek, wetlands and riparian areas has been added to Chapter 3 section 3.9 of the FEIS. Mitigation for Sowers Creek includes a 150 foot buffer along each side of Sowers Creek for well pads and roads, with the exception of stream crossings (section 3.9.2.8).
007	21	EPA	Svoboda	RIP	Further, we recommend that avoidance be extended to all wetlands, pending a CWA jurisdictional determination. EPA recommends that wetlands of all sizes should be avoided, not only those greater than 40 acres in size that are protected by lease stipulations.	The EIS has been revised to reflect that no well pads or roads (other than essential crossings) would be placed in drainages with defined bed and banks. In addition, drainages with distinctive riparian (i.e. wetland) vegetation would be avoided by a margin of at least 50 ft.The operator would be required to avoid and minimize impacts to wetlands and waters of the US during the site-specific Section 404 permitting process. Because this is not a leasing decision, additional lease stipulations have not been attached or required.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
005	2	Duchesne County Commission	Hyde	SCO	It is the position of Duchesne County that: a. Access to public lands for mineral development must be increased in the economic interest of the county citizens and government.	Noted. See section 3.14 transportation for maintenance and transportation plans related to this project.
003	1	Uintah County	Burns	SOC	Uintah County is extending our support of this proposed drilling project, as it will greatly benefit the economic stimulus of the Uintah Basin area.	Noted.
005	1	Duchesne County Commission	Hyde	SOC	The project is in compliance with the Duchesne County General Plan, which states county policies for energy development as follows: Energy and Mineral Resources: The oil and gas industry has been a significant economic factor in Duchesne County since the early 1970's. The industry provides employment and economic opportunity and accounts for a significant percentage of the County's tax base. For three decades the wealth created by oil and gas development has provided for the growth of local government services. It has helped build schools, roads, public buildings, utility infrastructure and family fortunes. Historically, much of this activity has taken place on private land. Trends since the late 1980's have emphasized development of oil and gas on public lands. Access to public lands is critical to the development of energy and mineral resources.	Noted.
005	14	Duchesne County Commission	Hyde	SOC	Section 3.16 provides the Socio-economic analysis of the project. We note that much of the population, income, and labor force data in this section are 2006 vintage or older. This obsolete data should be updated using readily available data from such agencies as the Utah Department of Workforce Services and the Governor's Office of Planning and Budget.The housing shortage mentioned on Page 241 was true during the 2006-2008 energy boom; but there is no longer a housing shortage after the energy bust beginning in late 2008.Crime data on Pages 241-242 are also obsolete and should be replaced with data readily available from local law enforcement agencies.Tax data beginning on page 244 is also 2006 data, which is obsolete. Updated information is readily available from the Utah State Tax Commission.	Data has been updated, as more recent data was available.
005	15	Duchesne County Commission	Hyde	SOC	Page 240 and 254 make reference to a 34.8% housing vacancy rate in Duchesne County and that there is thence a large supply of available housing for new workers associated with the project. This statistic is deceiving in that a significant number of such vacant units are really seasonal or secondary dwellings occupied for weekend/vacation purposes. These may be counted as vacant by the census, but they are not truly vacant and available housing units.	This statistic has been updated and a comment added to indicate that it varies seasonally and yearly.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	27	State of Utah, Public Lands Policy Coordination	Harja	SOC	Subsection 3.16.2.2, Page 256, line 116 and 17, this discussion is too brief and does not provide the reader with enough information for a transparent understanding of how the future life-of-project tax revenues were estimated. The discussion should include information on the estimated ultimate recovery (EUR) of oil and gas for an average well in the South Unit, and the prices used for oil and gas to derive the estimated value of the future production from which the various taxes were calculated. These data on volume and price for oil and gas production should also be included in table 3-78.	Life of project taxes estimated by Berry Petroleum; specific prices for oil and gas not used. Text inserted regarding 2008 oil and gas prices being used to make determinations of tax revenue. The EUR should be included in the alternative description, not just in the socioeconomics discussion.
006	36	State of Utah, Public Lands Policy Coordination	Harja	SOC	Subsection 3.16.2.2, Page 257, Table 3-78, the title of this table should be modified to read "Estimated Royalty, Severance, and Conservation Tax Revenue to the State by Alternative over the Life of the Project." Further, the table should include addition rows to provide data on the EUR of oil and gas, as well as estimated prices of oil and gas used in estimating the value of oil and gas production from which the taxes were calculated. Finally, it would be helpful for the reader to have in parentheses after each tax the percentage of the value of production that each tax collects [i.e. Royalties (125%), Severance (2.5%), etc.]. This would allow the reader to check the calculations in the table.	Table retiled, as suggested. prices of oil and gas not available. Tax percentages added.
007	38	EPA	Svoboda	SOC	Environmental Justice The Draft EIS (p. 248) states that "None of the communities within the study area are considered environmental justice communities because their minority populations do not exceed 50%." EPA recommends that the Forest Service revise and elaborate on this statement to better reflect the CEQ guidance. First we note that since 50% minority is not an established criterion to determine whether EJ communities are present, the grounds for determining that minority populations are not significant enough to warrant specific EJ consideration need to be more fully described. Second, please revise the statement to make clear that it is only with respect to minority populations that the Forest Service has determined that EJ is not a potential concern for this project. The presence of low income populations or Indian tribes should be considered as well in determining whether potential disproportionate impacts to EJ communities should be a concern for this project.	The FEIS was revised to cite CEQ criteria used in this analysis and to clarify how communities in the study area meet the criteria for minority and/or low-income population. Based on the refined analysis, the cities of Duchesne and Roosevelt meet the criteria for an environmental justice population.
007	39	EPA	Svoboda	SOC	Due to the classification of Duchesne County as a low-income area and the location of the project in Indian country. EPA notes that EJ concerns should be thoroughly evaluated in the EIS for the South Unit Project. As noted in the Draft EIS, human health, economic, and social effects of federal actions on potential EJ communities should be analyzed. The document adequately addresses social and economic concerns, but does not discuss the potential for disproportionately high adverse human health impacts from the proposed project. We recommend that potential health impacts be added to the discussion in the Final EIS. Oil and gas development frequently results in environmental impacts that could be of particular concern to the health of local residents, most especially with regards to air quality and water	The FEIS was revised to cite CEQ criteria used in this analysis and to clarify how communities in the study area meet the criteria for minority and/or low-income population. Based on the refined analysis, the cities of Duchesne and Roosevelt meet the criteria for an environmental justice population, however Duchesne County does not meet the criteria, as it did using the methodology in the DEIS. The refined analysis in the FEIS now addresses disproportionate impacts to environmental justice populations both in terms of the physical and natural environment, and human health.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	40	EPA	Svoboda	SOC	Analysis of environmental justice in the EIS should further include consideration of impacts on subsistence resources for minority or low-income communities. The Draft EIS notes that hunting is a principal recreational use of the project area, especially for elk and deer. The supplemental analysis should consider whether nearby minority or low-income communities rely on hunting in the project area for subsistence, or explain why their hunting will not be affected by the project.	Low income citizens in the area may indeed choose subsistence hunting as part of their household support, particularly in an area like the South Unit, where big game is well supported on the land and by management agencies. The recreation Section 3.12, Recreation, addresses impacts to hunting opportunities; the effects to those hunting for subsistence would be no different. Minority and low income citizens would not be differentially effected; they may have lower success rates or choose to hunt in another nearby area during oil and gas development activities.
004	18	U.S. Department of Interior, Office of Environment	Stewart	SSS	Section 365 of the Energy Policy Act of 2005 established a Pilot Project with the intent of improving efficiency and effectiveness of processing oil and gas use authorizations and environmental stewardship on federal lands. Under the Pilot Project, a Memorandum of Understanding (MOU) was entered into between various federal agencies including the USFWS and US Forest Service. One of the key principles of the MOU was to improve interagency coordination and cooperation on oil and gas development like the subject project. Early coordination on projects like this provides opportunities for inclusion of proactive conservation measures, early resolution of potential conflicts, and reduced consultation time. The USFWS recommends that the Forest Service take advantage of staff they have dedicated to the Energy Pilot Project on future oil and gas projects in the Uintah Basin area. They are available to help evaluate alternatives and their effects to sensitive listed species at an early stage in the planning process	Noted. The Forest Service has been working with Pilot Office staff, including those representing USFWS.
004	19	U.S. Department of Interior, Office of Environment	Stewart	SSS	On March 5, 2010 the greater sage-grouse was identified as warranting protection under the Endangered Species Act, and thus it is a candidate species. With this recent decision, it is imperative that Federal land management agencies design projects to reduce impacts on sage grouse populations. The project area contains over 1,300 acres of brooding habitat and over 4,700 acres of wintering habitat. Under all alternatives, but more so under the Proposed Action, a significant amount of these two important habitat types will be directly and indirectly affected as a result of development.	Discussion of sage-grouse in Ch 3 updated to reflect Candidate status (section 3.9.2.1). Additional sage grouse analysis and mitigations are included in the FEIS and Biological Evaluation prepared for this project.
004	20	U.S. Department of Interior, Office of Environment	Stewart	SSS	Various studies have shown that oil and gas development can negatively impact sage-grouse populations and their habitat. Lek persistence was positively influenced by the proportion of sagebrush habitat within 6.4 km (4 miles) of the lek (Walker et al. 2007). Sage-grouse avoided suitable wintering habitats once they were developed for energy production (Doherty et al. 2008). For these reasons, the USFWS recommends no new surface disturbance associated with this EIS be allowed within greater sage grouse brooding and wintering habitats. If development in these habitats is allowed to proceed, they recommend the following conservation measures be implemented: 1. Use topography and/or the latest muffling technology to ensure noise levels do not exceed 45dB within 5 km (3.1 miles) of a lek; 2. No surface disturbing activities within identified crucial wintering habitat between December 1 and March 15; and, 3. No permanent structures or facilities within identified crucial wintering habitat. 4. Well density should not exceed 1 well pad per square mile within sage grouse brooding habitat	More information is found in the MIS Report and Biological Evaluation prepared for this project. Some suggested text added to Chapter 3 of the FEIS. Additional sage grouse analysis and mitigations (including suggested mitigations) are found in the FEIS, MIS Report, and Biological Evaluation prepared for this project.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	24	U.S. Department of Interior, Office of Environment	Stewart	SSS	Page 32, line 1 - USFWS recommends pump-jacks and compressor stations be fitted with the latest muffling technologies to ensure noise levels do not exceed 45dB within 5 km (3.1 miles) of a lek.	This mitigation is included with Alternative 4. Refer to the FEIS, Biological Evaluation, and MIS Report prepared for this project.
004	27	U.S. Department of Interior, Office of Environment	Stewart	SSS	Page 129, line 10 - USFWS recommends the Forest Service provide further clarification as to why depletions associated with this project would not constitute a new depletion to the Upper Colorado River System. Previously permitted water sources have not necessarily gone through formal consultation. At least two of the proposed water sources listed in "Appendix A" were permitted after 1988 and would constitute new depletions. Additionally, water sources listed must have an intended use for oil and gas development and not be limited to only livestock or irrigation. Please provide water right numbers that will be used for the remaining proposed water sources listed in "Appendix A". They also request you provide the total amount of water that will be required for construction and maintenance of this project. Any new depletion to the Upper Colorado River System greater than 0.1 acre feet requires formal consultation with the USFWS. At this time it appears formal consultation with their Utah office will be required for this project.	Further clarification has been added and water deletions are discussed further in section 3.6. Through consultation with the Fish and Wildlife Service it is expected small depletions (<100 acre-feet/year) would occur to the Duchesne River system as a result of the Proposed Action. No diversions of any perennial or ephemeral surface water drainages within the Project Area would occur. As a result, no effects to drainage or river health from changes in stream flow related to water consumption would occur within the project area. No groundwater wells are proposed in the Project Area and therefore no alterations to the groundwater or localized aquifer depletions are expected.
004	28	U.S. Department of Interior, Office of Environment	Stewart	SSS	Page 146, beginning line 22 - The analysis of potential impacts to sage-grouse is outdated and could be substantially improved by reviewing and incorporating more recent peer-reviewed literature regarding the impacts to sage-grouse from energy development activities in Wyoming. The effect of oil and gas development and related habitat fragmentation on sage grouse in this section was only analyzed to 0.25 miles from disturbance. Recent publications by Holloran et al, have documented sage-grouse avoidance of traditional winterconcentration habitat following disturbance by energy development, and more recently,yearling male and female sage-grouse avoidance of natural gas field infrastructure by 950 meters, while birds reared in areas of oil and gas activity had reduced annual survival rates. In addition, Aldridge (2007) has recently published a peer-reviewed document predicting the probability of persistence of sage-grouse leks based on the level of disturbances within various distances of lek sites. Naugle, Doherty and Walker have also published articles since 2005 which would be pertinent to the sage-grouse discussion here, such as the discussion that impacts to sage-grouse can be documented at one disturbance (well) per section, and that impacts to sage-grouse can be documented out to 4 miles from a disturbance. Given this, we disagree with the assessment that the project will not cause loss of viability to sage grouse populations in the area. It is quite possible that local extirpation of the Anthro Mountain sage grousepopulation will occur as a result of the amount of development proposed in the EIS as well as on surrounding BLM administered lands.	Comments acknowledged. A literature search was conducted, and the analysis in the EIS was updated, based on current research information. The analysis in the EIS, BE and MIS Report was changed to follow the process used and developed in Wyoming for analyzing impacts to sage grouse from oil & gas development.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	29	U.S. Department of Interior, Office of Environment	Stewart	SSS	Page 148, line 2 - The Cumulative Impact Analysis Area is described as only the boundaries of the Project Area. The Project Area abuts BLM along its eastern boundary, an area which is also undergoing intensive oil and gas development (GASCO and Newfield). In the Affected Environment section of the document, it is pointed out that at least a portion of this greater sage-grouse population is migratory, traveling distances of over 20 miles to the Emma Park area north of Price, which is also undergoing oil and gas development. The Cumulative Impact Analysis Area for sage-grouse should be enlarged to include known migration areas, as well as the area to the east on BLM where sage-grouse were formally present, but may have been eliminated by the intensity of oil and gas development in that area.	The analysis in the EIS, BE and MIS Report prepared for this project was changed to follow the process used and developed in Wyoming for analyzing impacts to sage grouse from oil & gas development. Additionally, discussion of the wintering areas used by Anthro sage grouse was included in the EIS, BE, and MIS Report, as well as how oil and gas exploration in those areas may effect the Anthro sage grouse population.
004	30	U.S. Department of Interior, Office of Environment	Stewart	SSS	Page 150, lines 132 to 135 - The statement that disturbance to sage-grouse habitat would be considered substantial after a 20% loss of habitat, based on Connelly's (2000) statement that burn treatments should not exceed 20% of brood-rearing or wintering habitat, is problematic in that it compares a temporary, short-term disturbance to a permanent, long-term disturbance and loss of habitat. A different significance threshold should be calculated, based on review of the latest sage-grouse literature.	This has been addressed by using the Wyoming DDCT process for sage-grouse impacts analysis.
005	12	Duchesne County Commission	Hyde	SSS	For those concerned with Greater Sage grouse, we note on Page 132 of the DEIS that "There are no active sage grouse leks within the Project Area; one lek is immediately adjacent to and three leks are located within 2 miles of the Project t Area." Sage grouse populations are increasing in the area according to recent surveys. Mitigation measures (seasonal timing stipulations and activities near lek sites - see Page 146), will allow the project to proceed without causing a loss of viability of sage grouse populations in the area.	Noted.
006	3	State of Utah, Public Lands Policy Coordination	Harja	SSS	The USFWS recently ruled that the greater sage-grouse was warranted for listing under the Endangered Species Act, but precluded from listing at the present time, because of higher priorities elsewhere involving other plant or wildlife species. The Ashley National Forest and Berry Petroleum Company should carefully consider all aspects of the project that have potential to cause sage-grouse impacts.	EIS has been revised to reflect the recent change in status of the greater sage-grouse. Analysis of impacts are found in Chapter 3 of the EIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	4	State of Utah, Public Lands Policy Coordination	Harja	SSS	UDWR has concerns about the statement found on pages 158 and 159 of the DEIS: "Therefore, it is determined that… habitat for this species." UDWR is concerned that increased, project-related traffic through and adjacent to identified, active sage-grouse leks may cause problems with attendance at the leks. Even though there are no active leks identified within the project area, many active leks occur on the proposed road access areas. Therefore, much of the impacts related to the project may extend beyond the specified project boundary. Roads of special concern are Nutter's Ridge Road and Wire Fence Road. Any increase in traffic on these roads could impact lek activity and be detrimental to the sage-grouse population as a whole. For example, the sage-grouse on Nutter's Ridge lek strut very near the road and at times can be found in the road. Traffic-related disturbances can affect lek attendance, which directly translates to decreased productivity. Traffic-related mortality due to grouse/vehicle strikes is also a possibility and could pose a threat to this sage-grouse population.	Analysis and discussion of impacts for sage grouse has been updated in the EIS. Added to this section "Leks along existing roads that would be used for accessing the Project Area (e.g., Nutter's Ridge Road and Wire Fence Road) could be impacted by increased traffic. Traffic-related impacts include decrease lek attendance leading to decreased productivity, as well as direct mortality due to vehicle collisions." Additionally, the following mitigation has been added to Alternative 4, "Project-related activities and vehicle access will not be allowed on the Nutters Ridge Road (FSR 333) or the Wire Fence Ridge Road (FSR 332), south of the Operator's current lease area".
006	5	State of Utah, Public Lands Policy Coordination	Harja	SSS	UDWR agrees with the mitigation measures outlined in the DEIS, and additionally requests the FEIS state that any project-connected activities occurring within 2 miles of an active lek - whether within the delimited project area or not - need to follow the proposed mitigation measures.	DDCT process for sage-grouse impacts analysis has covered this.
006	6	State of Utah, Public Lands Policy Coordination	Harja	SSS	Additional mitigation measures that should be implemented to reduce impacts on sage-grouse include (a) the installation of mufflers on all combustion-powered production equipment within a two-mile radius of each lek and (b) the installation of anti-perch devices on equipment and power lines associated with the project.	Mitigation measures were added to the Preferred Alternative, to reduce raptor perching availability, and also to reduce noise impacts, as recommended by the most recent sage grouse literature. There are no power lines being proposed for this project, and thus no need for anti-perch mitigations associated with power lines.
006	15	State of Utah, Public Lands Policy Coordination	Harja	SSS	The Duchesne River to the north and down gradient from the project area sustains healthy populations of brown trout, flannel mouth sucker (a conservation agreement species), and northern leopard frog, which is currently under review by the U.S. Fish and Wildlife Service for listing under the Endangered Species Act. The Duchesne River supports several different life stages of these species and is very important to both sport fish and native aquatic communities. While the project area does not encompass many perennial streams or any streams that sustain fish, maintenance of the upstream watershed is essential to the health of downstream aquatic habitats. Disturbed earthen material from the construction of well pads, roads and pipelines may result in sediment entering waterways during intense storm events. Downstream ecosystems would be negatively impacted if large amounts of sediments were input into the stream. UDWR recommends using best management practices to control the movement of sediment from disturbed areas, and limiting construction activity to periods when flows in the drainage are low, rainfall is not expected to be plentiful, and snowmelt is not an issue.	Text added to Other Wildlife Species section in Chapter 3 section 3.9.2.12 of the FEIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	46	UEC, WG, SUWA, WRA, WWP		SSS	In addition to clear conflicts with the VQO standards specified in the LRMP, we are particularly concerned that the South Unit DEIS does not adequately meet management Indicator Species (MIS) and sensitive species direction under NFMA, as well as that found in the LRMP. Page 30 the LRMP requires the Forest to complete a GAWS inventory of all streams and that has not yet been done. Similarly, the LRMP requires completion of management plans for riparian and aspen ecosystem types. That has not been done yet, even though it appears the proposed action would involve significant cumulative impacts to each.	Stream surveys and vegetative surveys are ongoing. Stream surveys are conducted annually as funding allows. A long term vegetative monitoring program has been continuing on the Forest for many years. This program monitors vegetation types, including aspen and riparian, and evaluates them to determine if they are moving towards desired condition. The project area does not affect any aspen stands. There is a potential for access roads south of the project area to indirectly affect aspen stands from noise related to traffic. However, these indirect impacts to aspen obligate wildlife species are discussed in the MIS Report, BE, and FEIS.
010	47	UEC, WG, SUWA, WRA, WWP		SSS	MIS and water quality direction and duties are not assured by the proposed action or the analysis in the South Unit DEIS. For example, the standard requiring that all streams be maintained at least at a BCI of 75 or above and a HCI of 42 or above has not been met, and the proposed actions would only work to move the Forest further out of compliance. For some streams, one cannot determine compliance with the standard on LRMP p. IV and elsewhere because necessary surveys/monitoring has not been done. The proposed action also involves cumulatively adverse affect to at least some TEPCS species/habitats (some of which have insufficient monitoring data) even though such impacts and monitoring gaps are prohibited by standards and guidelines in Chapters IV and V of the LRMP.	The MIS report and FEIS have been updated to include monitoring of macroinvertebrates. The standard for all streams to be maintained at least at a BCI of 75 is being met. Macroinvertebrates were sampled in Sowers Creek in 2008. Results indicate a BCI of 113 for Sowers Creek. For discussion of cumulatively adverse affects to TEPCS species/habitats refer to the MIS, BE and BA prepared for this project.
005	10	Duchesne County Commission	Hyde	TRA	During the scoping period, in the fall of 2007, Duchesne County commented favorably on this proposal, expressing concern that the operator be required to coordinate with the Duchesne County Public Works Department to ensure that county roads serving the project area are adequately maintained and repaired as a result of project traffic. This includes adequate dust control, which is addressed in the DEIS. We continue to request these considerations be made with respect to our county-maintained roads.	Added to 3.14.2: "Consult with the County, UDOT, and adjacent land managers (i.e., BIA) to ensure that roads serving the project area are adequately maintained and repaired."
005	17	Duchesne County Commission	Hyde	TRA	We hope that the issue of road construction and reconstruction within "Inventoried Roadless Areas" does not result in another lengthy delay. The project area is traversed by several county roads (see Figure 3-22) and there are numerous other roads existing on the ground that are not recognized by the Forest Service. These can include roads that were permitted by the Forest in the past; however, the permits have expired. Also common on the ground in such areas are roads created by unauthorized activities, which are used for grazing, recreation, hunting and fishing. To designate any portions of the project area "roadless" gives a false impression of what actually exists within the area. We urge USDA Secretary Vilsack to take this into account as he rules on this project. Road construction and reconstruction will be necessary for Berry Petroleum to exercise their valid, existing lease rights sold to them many years ago.	The roadless section of the EIS has been updated to better disclose impacts to inventoried roadless areas from this project, as well as impacts to potential wilderness areas. The action alternatives for this project are in compliance with the 2001 Roadless Rule, which allows for reasonable development related to prior lease rights. There are no County roads within the project area. All of the roads within the project area are Forest Service Jurisdiction Roads. However, some Forest roads within the project area are under maintenance agreement with the County, and there are County roads which lead to the project area. There are also numerous unauthorized roads.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	26	UEC, WG, SUWA, WRA, WWP		TRA	Due to the massive scale of such road construction proposed, it is certain that the proposed action triggers the need for a road analysis on the south unit sufficient to inform decisions removing and adding all maintenance level roads involved. Past Forest-wide Roads Analysis Report (RAP) processes did not contemplate 100 miles of new system road construction Forest wide, let alone in one Ranger District. The South Unit DEIS and associated RAP are both insufficient under the 2001 Transportation Policy, the 2005 OHV Rule, and NEPA. While the South Unit DEIS says on page 31 that a transportation plan has been developed for all roads to be used/constructed, gated, and maintained over time, a closer reading of the subsequent sections of the DEIS discloses that the transportation plan "would be submitted for each phase" of the 20+ year long project. South Unit DEIS, p. 219. These transportation plans would be created for each of up to five future phases, or Plan of Development (POD).	The Forest is currently in the process of Subpart A of Travel Management. However, since the proposed project roads will be temporary non-Forest System roads, it is not necessary to analyze these roads under Travel Management. The new access roads are being analyzed under this EIS. Once oil and gas production at the well pads has ceased, these roads will be obliterated. During well production, temporary access roads will be closed to the public and will not require Forest Service maintenance.
010	27	UEC, WG, SUWA, WRA, WWP		TRA	Not only must this EIS be informed by a RAP for the 100 miles of new road construction, but this EIS must (under NEPA) include a description of impacts analysis of each POD. It is not acceptable under the transportation policy, NEPA, or the standards of the APA to hold the actual environmental analysis until some future non-public and non-NEPA process.	Since the proposed project roads will be temporary non-Forest System roads, and not open to the public, it is not necessary to analyze these roads under Travel Management. The new access roads are being analyzed under this EIS.
010	28	UEC, WG, SUWA, WRA, WWP		TRA	We understand that the development of the RAP and Report itself is not required to be a part of a NEPA process, but it may be done as such. Regardless, roads management decisions such as that proposed here must be informed by the completed RAP. In this case it appears no RAP has been prepared to support the 100 miles of new roads contemplated for authorization, whether in or out of a NEPA or public process. Further, the status of roads and trails in the watershed will not change as a product of the RAP. Rather, the information gathered and generated in the RAP may be used to inform a separate NEPA process (such as the proposed EA, which must be an EIS) to open/close, and (re)construct routes in the area. If and when you proceed with development of the RAP, please contact us for involvement.	Since the proposed project roads will be temporary non-Forest System roads, and not open to the public, it is not necessary to analyze these roads under Travel Management. The new access roads are being analyzed under this EIS.
010	29	UEC, WG, SUWA, WRA, WWP		TRA	Since it is required to be science based, we request that the Forest rely upon the processes outlined in Miscellaneous Report FS-643, and that the research be included and summarized on the affects of roads such as those proposed, as well as those that would be indirectly created or promoted via the proposed action.	Miscellaneous Report FS-643 is an approved publication that can be used to complete a RAP as part of Travel Analysis but it is not required. Since the proposed project roads will be temporary non-Forest System roads, and not open to the public, it is not necessary to analyze these roads under Travel Management.
010	30	UEC, WG, SUWA, WRA, WWP		TRA	We understand that the companies have expressed a desire to proceed with the requested new road construction and oil and gas well development as soon as possible. As a result, the Forest Service may currently feel the need to quickly complete the bare minimum for roads analysis, effects analysis, with the minimum amount of alternative development as possible. We urge the Forest to proceed with a project level roads analysis that is meaningful, useful, and in which the public is afforded opportunity for input early in the development of that RAP.	Since the proposed project roads will be temporary non-Forest System roads, and not open to the public, it is not necessary to analyze these roads under Travel Management. The new access roads are being analyzed under this EIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	32	UEC, WG, SUWA, WRA, WWP		TRA	In relation to the RAP development and NEPA analysis, the UEC notes that it does not need or require any new roads to satisfy the proposal, nor for continued general public motorized use in the project area an watersheds. Accordingly, we would like the RAP to fully consider that some of the public does no need or desire a single section of road in this area and find it preferable to have no roads.	Comments Noted. Since the proposed project roads will be temporary non-Forest System roads, and not open to the public, it is not necessary to analyze these roads under Travel Management. The new access roads are being analyzed under this EIS.
010	33	UEC, WG, SUWA, WRA, WWP		TRA	The economic cost of the proposed new road construction must be rigorously evaluated. The Forest already has a large maintenance and deferred maintenance backlog. Additions of new classified roads will only compound this problem.	The roads are not being constructed, funded, or maintained by the Forest Service and will not be classified roads.
010	34	UEC, WG, SUWA, WRA, WWP		TRA	I. Inadequate Range of Alternatives: No Analysis of a No Road Construction in IRA Action Alternative. The South Unit DEIS recognizes impacts to Inventoried Roadless Areas (IRA) and Potential Wilderness Areas (PWA) as significant issues. Indeed, all action alternatives involve extensive destruction and complete loss of certain IRAs and PWAs. This is a quintessential conflict among alternative uses of available resources important enough to require the development of alternatives for a major federal action under NEPA. Comments submitted during scoping requested that an action alternative be developed that allows minimal but reasonable oil and gas field development with no new road construction in the IRA. In light of the roadless area conservation rule it should further be self-evident that such an alternative would be required by NEPA for detailed analysis in the EIS. Nonetheless, the South Unit DEIS fails to analyze such a reasonable alternative. Chapter 2.3 shows that the Forest did not consider a detailed study of an alternative action of no new road construction IRA.A "reasonable oil/gas field development with no new road construction in IRA" action alternative needs to be included. This should be done in a revised EIS that is circulated (again) for public comment prior to a ROD being signed.	This is addressed in Section 2.3.5 of the FEIS.
010	35	UEC, WG, SUWA, WRA, WWP		TRA	II.2001 Roadless Rule is in Effect. Pages 205-207 of the South Unit DEIS contain a timeline of events surrounding the 2001 Roadless Rule that is not up to date. The last two events in the timeline include (1) the December 2, 2008 District Court partial stay issued by Judge Laporte that limit her injunction to the Ninth Circuit and New Mexico, and (2) a May 2009 Secretary of Agriculture memo that reserved decision-making authority to his office for projects (such as this) that involve road construction within IRAs. Since that time more Secretary/ WO level memos have been issued that modified the May 2009 re-delegation of decision-making authority. Of more importance, however, is the published August 5, 2009 Ninth Circuit Court of Appeals ruling in Cal. Ex rel. Lockyer v U.S. Dep't of Agriculture, 2009 WL 2386403. The Ninth Circuit ruling is of national scope and is still in effect. The language of the ruling is clear that its relief (reinstating the 2001 Roadless Rule) is national, and not limited to New Mexico and the Ninth Circuit.	Section 3.13.1 has been updated to reflect the current legal status of the 2001 Roadless Rule and the decision making process for projects in inventoried roadless areas. At the time of the Lockyer decision, the Wyoming District Court's injunction of the Roadless Rule was still in effect. This resulted in conflicting court decisions regarding the 2011 roadless rule which have yet to be fully resolved. Currently all Forest Service decisions involving construction or reconstruction of roads or the cutting, sale or removal of timber in inventoried roadless areas are subject to Secretary of Agriculture review per the Secretary's Memorandum 1042-156 (dated May 30, 2011, available at www.roadless.fs.fed.us). This review process will ensure that actions in IRAs are carefully considered, and comply with any applicable laws.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	36	UEC, WG, SUWA, WRA, WWP		TRA	III. Action Alternatives Do Not Adhere to the 2001 Roadless Rule.The South Unit DEIS fails to address or even passively consider compliance with the 2001 Roadless Rule. That effects to (post-2001 roadless) PWA were considered (albeit inadequately) is not sufficient for determining compliance with the 2001 Roadless Rule and studying effects of the 37 miles of proposed new road construction inside IRA to that rule's different set of Roadless Area Characteristics. Roadless area characteristics have nothing to do with Wilderness by definition. For example, motorized recreation inside IRA is a roadless area characteristic of positive value, whereas such activity is in conflict with Wilderness values. Promoting and restoring ecosystem function and composition consistent with the current climatic period is another roadless area value specific to IRA and the Roadless Rule. Conversely, such active vegetation management is prohibited in Wilderness and is not a Potential Wilderness Area value or attribute.	An alternative was considered, which would limit surface disturbance within roadless areas (see section 2.3.5 for the rational as to why it was not analyzed in detail). The roadless section of the EIS has been updated to better disclose impacts to inventoried roadless areas from this project, as well as impacts to potential wilderness areas. The action alternatives for this project are in compliance with the 2001 Roadless Rule, which allows for reasonable development related to prior lease rights.
010	37	UEC, WG, SUWA, WRA, WWP		TRA	Furthermore, the acres inside the project area that are designated IRA do not match those considered in the South Unit DEIS for PWA. There is significantly more IRA acreage than PWA. Assuming, arguendo, that roadless area characteristics and values did equal potential wilderness area characteristics and values, it would be impossible for any study of new road construction inside PWA to satisfy requirements to study the same inside IRA because there are many acres of land that are designated IRA but not PWA. One must look outside the EIS to know this as there is no map of IRA in the South Unit DEIS, let alone one with the new road construction overlaid on IRA. When we did this it became clear that there are new well pads and new road construction inside the acreage that is IRA but not PWA. IRA maps (that are not in the South Unit DEIS), when compared to the proposed action maps and figure 3-21 map of the PWA boundaries used, show that there is something over 50 new well pads and may miles (possibly over a dozen) of new road construction proposed in the lands that are IRA but not PWA.	The roadless section of the EIS has been updated to better disclose potential impacts to inventoried roadless areas from this project, as well as impacts to potential wilderness areas. As noted, new roads and well pads are being proposed for construction within inventoried roadless areas, under all action alternatives considered by the EIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	38	UEC, WG, SUWA, WRA, WWP		TRA	Ecological and scientific values are of much greater importance to IRA than for PWA. Even if analysis in the South Unit DEIS to PWA was adequate, it would not satisfy requirements to analyze impacts to values and attributes inherent in IRA and not PWA. For example, the South Unit DIES fails to disclose the scientific research recommendations relevant to the importance of all IRAs and their connective habitat. Instead, and we do not charge that this was deliberate, the Forest Service misuses the criteria it developed for PWAs to avoid meaningfully addressing the harmful impacts of new oil pad construction, chemical pollution, extensive heavy machinery use, and new road construction that is on an unprecedented scale within environmentally significant IRA. Scientific research notes that IRAs, absent functioning roads, provide important undisturbed habitat for numerous forest-dependent species of concern. The importance of such areas is not appreciably diminished by the vanishing presence of the long past evidence of limited levels of prior management. The scattered presence of a few eroding stumps from the long-ago selective removal of small numbers of scattered trees, non-navigable remnant remains of previous vehicle incursions, evidence of livestock grazing (which also occurs in wilderness), and decades old skid trails that are slowly returning to forest vegetation – though these may be considered by the Forest Service as not meeting their PWA criteria – do not significantly detract from the ecological importance of the now largely undisturbed roadless forest habitat such inventoried IRA provides.When compared to the different criteria for IRA, the PWA analysis criteria the Forest Service exclusively utilizes to supposedly evaluate the significance of unroaded areas is comparing apples to oranges. The South Unit DEIS fails to disclose relevant scientific research recommendations that emphasize the ecological importance of protecting all roadless areas and their connective, contiguous habitat. The South Unit DEIS instead substitutes its exclusive PWA criteria to obfuscate the ecological significance of the project's IRA and associated attributes and values that are not shared with PWA. Scientific research documents well the critical significance of IRA as core habitat and refugia for numerous forest dependent species of concern including TEPCS species and habitats.	The roadless section of the EIS has been updated to better disclose impacts to inventoried roadless areas from this project, as well as impacts to potential wilderness areas. The action alternatives for this project are in compliance with the 2001 Roadless Rule, which allows for reasonable development related to prior lease rights.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	39	UEC, WG, SUWA, WRA, WWP		TRA	IV. The 2001 Roadless Rule Has Substantive Restrictions for IRAs Leased Before and After 2001. Almost all of the lands in the project area were first leased before 2001. This does not mean, however, that the roadless rule would not apply or restrict the proposed action in any way, despite those leases' language specific to pre-2001 oil/gas leasing. There are at least two reasons that this is not entirely correct. First, post-2001 re-issuance and/or renewal of leases may change the status of non-negotiable rights prior to 2001. Second, the Rule contemplates a degree of substantive restriction on oil/gas leases issued before 2001, and was not intended to apply exclusively oil/gas leasing in IRA after 2001. The first reason is because the current legal status and year of the renewed leases suggests that prior existing rights may not apply to all leases in the project area. The EIS needs to include a section disclosing the leasing history and current legal status of each of the leases involved. This is important because all or at least most of the leases in the project area were scheduled to expire sometime in the last five years. Most were initially tagged for expiration around 2008-2009. It appears that the current leasing contracts for most or all of the leases in the area would appear to post-date 2001 due to issuance of new or renewed leasing contracts. The language in each of the renewed contracts thus becomes very important when it comes to the applicability and scope of the 2001 roadless rule.	Although oil and gas leases are generally issued only for a specified number of years, once production has been demonstrated for any given lease, that lease is automatically extended to cover the timeframe of continuing production. As such, productive oil and gas leases don't expire until they are no longer deemed economically productive. The action alternatives for this project are in compliance with the 2001 Roadless Rule, which allows for reasonable development related to prior lease rights, including the construction of new roads. However, the 2001 Roadless Rule does place limits on road construction in roadless areas relative to prior lease rights. New road construction within roadless areas must be done in a manner which prevents unnecessary or unreasonable surface disturbance, and the new roads must be reclaimed when no longer needed. These restrictions have been applied to this project.
010	40	UEC, WG, SUWA, WRA, WWP		TRA	As a corollary to this first reason we also comment that the South Unit DEIS is insufficient in its omission and lack of analysis of the fact that at least some of the leases renewed in the late 1990s and/or early 2000s added Controlled Surface Use stipulations that imposed some kind of special operating constraints on Forest Service "roadless areas" that read as equal to that assigned to Semi-primitive Non-Motorized areas. In light of the fact that the term "Potential Wilderness Area" did not first appear in the Forest Service NFMA implementing rules found in its FSH/FSM until later revisions, made in response to the 2005 and 2008 NFMA regulations, it is clear that use of the term "roadless areas" is a reference to places in the Forest Service IRAs.	Lease stipulations for the oil and gas leases related to this project are listed in Appendix A. These stipulations include a Controlled Surface Use for roadless areas, requiring developments (such as roads) to be constructed and reclaimed in a way that minimizes impacts to roadless area.
010	41	UEC, WG, SUWA, WRA, WWP		TRA	The second reason is that the 2001 roadless rule does in fact apply some (albeit reduced) substantive restrictions on new road construction to leasing rights pre-dating 2001. The South Unit DEIS is insufficient under this rule and NEPA due to insufficient attention to these requirements for IRA. 66 FR 3244-041, 2001 explain in part: "The Department has decided to adopt a more limited exception at 36 CFR 294.12(b)(7) to allow road construction needed in conjunction with the..... This provision allows, but does not require, road construction and reconstruction. These decisions would be made through the regular NEPA process. For example, this paragraph does not supersede land management plan prescriptions that prohibit road construction. This exception only applies to lands in inventoried roadless areas that are currently under mineral lease. The agency has less than 1 million acres of high potential oil and gas currently under mineral lease. This provision maintains the status quo for entities that currently hold mineral leases, while at the same time limiting the potential impacts on roadless area characteristics.	Due to public comment and concerns, as well as the continuing uncertain legality of applying or not applying the roadless rule, analysis of effects to roadless characteristic in lands inventoried as roadless have been included in the FEIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	42	UEC, WG, SUWA, WRA, WWP		TRA	Most if not all of the action alternatives analyzed in detail (and even those considered but dismissed from detailed study) are not consistent with the restrictions (albeit more limited) on new road construction in the IRA relating to oil/gas leasing contract rights that pre-date 2001.	Restrictions due to roadless rule and pre-rule requirements on this lease are not described specifically as roadless area mitigations in the roadless section, but are addressed as design requirements for road construction and rehabilitation in the FEIS.
010	44	UEC, WG, SUWA, WRA, WWP		VRM	VQOs, for example are to be maintained or improved to prescribed standards, some of which include standards up to “retention” for management areas D and E. LRMP, p. IV-19.	While the management areas allow for standards up to retention, they also allow for standards as low as maximum modification. Maps of Forest VOQ, which were created from a combination of inventoried VQOs and Forest Plan Management Area standards, show the areas with modification and maximum modification VQOs throughout most of the project area. This is due to the area having 1) a "seldom seen" mapping classification due to the areas being not visible from sensitivity level one or two routes, and 2) the landscapes would be mapped with Variety Classes of B and C in most areas based on the absence of water or other landscape features of interest. Terrain and vegetation raise much of the landscape slightly above an overall rating of C; (A= highest variety/value, B=average or common, and C = minimal variety) This combination of mapping qualities results in an inventory VQO of modification and maximum modification, as shown in the table on page 43 of National Forest Landscape Management Volume 2 - Agricultural handbook 462,USDA Forest Service, 1977.
004	21	U.S. Department of Interior, Office of Environment	Stewart	WL	Page 24, line 1 - USFWS recommends closed loop drilling methods be used to reduce surface impacts, better safeguard terrestrial wildlife and migratory birds and to reduce the risk of pit contents being released to the environment. If reserve pits are used, they recommend the use of bird exclusion netting on all pits. Evaporation ponds containing concentrated brine solutions can cause bird mortality when birds enter the pits, ingest the brine, and die from sodium toxicity. Inefficient management of evaporation ponds can result in oil or visible sheens on the surface of the ponds which can cause mortality of migratory birds and other wildlife. Exposed oil or other hazardous materials (even as the result of an oversight or equipment malfunction) places the company at risk of violating the Migratory Bird Treaty Act (MBTA) should migratory bird mortalities occur. To prevent violations of the MBTA, the operator should be required to take proactive steps as described above to ensure that migratory birds do not come in contact with oil, sheens, or hazardous materials	Closed loop drilling was only specifically analyzed as a BMP for Alternative 3 in the FEIS. However, several mitigations were included in the EIS to minimize potential wildlife impacts from the proposed use of reserve pits. Discussion of reserve pit impacts and FWS recommendations to reduce impacts are in Chapter 3 Migratory Bird discussion
004	22	U.S. Department of Interior, Office of Environment	Stewart	WL	Page 27, line 30 - USFWS recommends best management practice (BMPs) that reduce impacts to wildlife be required throughout the project area instead of evaluating them on an individual well basis. Additional suggested BMPs not listed in the EIS include but are not limited to: low profile facilities, limited overhead power lines, screening stacks on heater-treater facilities to prevent bird entry, and reducing well pad size to the smallest area required for operations after construction is complete.	Several of these BMP's have been included in the EIS. Overhead power lines have not been proposed as part of this project. The Preferred Alternative was designed to minimize impacts to wildlife.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	23	U.S. Department of Interior, Office of Environment	Stewart	WL	Page 28, line 36 - USFWS recommends the use of the Utah Field Office Guidelines for Raptor Protection from Human and Land Use Disturbances (Romin and Muck,2002) which were developed in part to provide consistent application of raptor protection measures statewide and provide full compliance with environmental laws regarding raptor protection. Raptor surveys and mitigation measures are provided in the Raptor Guidelines as recommendations to ensure that proposed projects will avoid adverse impacts to raptors. Locations of existing raptor nesting sites should be identified prior to the initiation of project activities. Direct loss of nesting sites or territories should be avoided. Appropriate spatial buffer zones of inactivity should be established during crucial breeding and nesting periods relative to raptor nest sites or territories. Arrival at nesting sites can occur as early as December for certain raptor species. Nesting and fledging continues through August. Generally they recommend special buffers of 1.0mile for threatened and endangered raptors, 0.5 mile for other diurnal raptors such as goshawks, and 0.25 mile for nocturnal raptor species.	Protection of raptors (i.e. buffers) is included in the EIS. This BMP addresses protection of raptor nests, survey and inventory of nesting habitat, and mitigation to any known or discovered nests. See response below.
004	31	U.S. Department of Interior, Office of Environment	Stewart	WL	Page 162, line 26 - USFWS recommends vegetation removal activities take place outside the nesting season for migratory birds (May 15-July 15) to avoid impacts to nesting bird species unless nesting surveys are performed prior to vegetation removal.	The mitigation for migratory birds in the EIS requires surveys for FWS BCC and PIF priority species prior to surface disturbance during the breeding season (May 15th-June 30), and then restricts surface disturbance activities from occurring within a 0.1 mile buffer around nest locations or estimated nest locations. This will avoid or reduce impacts to migratory birds during the nesting season.
004	32	U.S. Department of Interior, Office of Environment	Stewart	WL	Page 163, line 13 - Activities should avoid to the extent possible, sensitive wildlife periods (breeding season, calving season, migration corridors). In particular, the Forest Service should evaluate and minimize impacts to migratory bird habitat focusing onspecies on the Service's 2008 List of Birds of Conservation Concern and species that are listed among the Partner's in Flight Priority Species. To help meet responsibilities under Executive Order 13186 (Responsibilities of Federal Agencies to Protect Migratory Birds), USFWS recommends conducting activities outside of critical breeding seasons for migratory birds; minimizing temporary and long-term habitat losses; and mitigating unavoidable habitat losses. If activities occur in the spring orsummer, they recommend conducting surveys for migratory birds to assist with efforts to comply with the Migratory Bird Treaty Act.	PIF species and BBC species are listed and analyzed in Table 3-38. The mitigation for these species has been updated to reduce potential impacts.
006	2	State of Utah, Public Lands Policy Coordination	Harja	WL	The Preferred Alternative substantially reduces the total number of disturbed acres, diminishes the required length of new or improved roadways, and effectively mitigates overall impacts to most wildlife species. Reducing the total acres of habitat lost or fragmented due to development is an important step toward preserving the wildlife habitat found in the area. UDWR believes that several further steps should be taken to better conserve wildlife inhabiting the project area. These additional species-specific mitigation measures are recommended in the subsequent sections.	Noted.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	7	State of Utah, Public Lands Policy Coordination	Harja	WL	Elk herds can be limited by the quality and availability of winter range. Of the 25,900 acres in the project area, approximately 20,420 acres occur within crucial elk winter range; this represents about 79% of the project area. A small portion of the project area will be directly disturbed, however, indirect and cumulative impacts will be more far-reaching. With increased road densities and additional human presence, elk inhabiting the project area could be forced into areas of lesser habitat quality. Elk are especially susceptible to disturbances, they are highly mobile, and will likely be displaced to some extent by increased project related activity. Further consideration should be given to the fact that a large portion of the formerly available winter range north of the project area has already been degraded through habitat loss and fragmentation associated with other oil and gas development activities.	Added suggested elk text to Chapter 3
006	11	State of Utah, Public Lands Policy Coordination	Harja	WL	Mule deer occupy the entire project area, with both crucial summer and winter habitats identified within the project boundary. Impacts within the scope of the project (not more than 4 wells per section) will most likely have no more than a moderate impact on the mule deer population in the area.	This has been noted in the EIS.
006	14	State of Utah, Public Lands Policy Coordination	Harja	WL	The DEIS recognizes 367 acres of substantial year-long pronghorn habitat within the project boundary. UDWR recently identified 805 acres of additional crucial yearlong pronghorn habitat within the project area. This new information should be reflected in the final document.	FEIS has been updated with the new data.
007	27	EPA	Svoboda	WL	The discussions of the grouse and of federally listed wildlife species should be revised in the Final EIS to reflect its change in status and to address the Candidate designation in all pertinent regulatory respects. Due to the extent of sage-grouse presence in the project area, EPA considers protection of important sage-grouse habitat to be a significant concern for the South Unit Oil and Gas Development Project.	Change made.
007	28	EPA	Svoboda	WL	FWS has pointed to habitat destruction and fragmentation occurring as a result of infrastructure related to energy projects and direct displacement by energy development as threats to sage-grouse. Likely impacts to sage-grouse from the proposed project include loss of habitat, avoidance of anthropomorphic-influenced areas, increased predation, increased exposure to West Nile virus, and increased human activity. Impacts to important habitat areas may be serious enough to cause abandonment	Fragmentation and other impacts are discussed in the revised sage-grouse section.
007	29	EPA	Svoboda	WL	As noted in the Draft EIS, maintaining large, continuous tracts of suitable habitat is likely to be critical to the sustainability of greater sage-grouse populations. EPA is particularly concerned that 80% of the sage grouse habitat in the project area will be lost in the Preferred Alternative (including the 0.25-mile buffer around roads where the Forest Service assumes habitat will be devalued enough to cause avoidance.) Removal of sagebrush habitat throughout the West leads to a significant cumulative impact on the Greater Sage-grouse.	The analysis of potential impacts to sage grouse from the project was revised, using the same process as is used in Wyoming. This Wyoming process only allows 5% of sage grouse habitat to be disturbed.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	30	EPA	Svoboda	WL	CEQ regulations require that the 'environmental consequences' section of an EIS address 'possible conflicts between the proposed action and the objectives of federal, regional, state, and local… land use plans, policies and controls for the area concerned' (40CFR 1502.16c). Consistent with these requirements, the Final EIS should fully explore possible conflicts and inconsistencies between the proposed action and sage-grouse-related plans and policies.	The alternatives and mitigation measures were designed to follow sage-grouse-related plans and policies.
007	31	EPA	Svoboda	WL	The Forest Service has concluded that proposed project activities may affect individual greater sage-grouse but would not cause a loss of viability to the population. This determination is based on a significance threshold of less than 20% disturbance to habitat within the portion of the ANF South Unit east of US 191. We recommend that the Final EIS fully explain the reasons for this significance threshold, particularly in the context of the Candidate designation.	The analysis of potential impacts to sage grouse from the project was revised, using the same process as is used in Wyoming. This Wyoming process only allows 5% of the sage grouse habitat to be disturbed. See the updated analysis for sage grouse included within the FEIS, BE, and MIS Report for this project.
007	32	EPA	Svoboda	WL	EPA appreciates the mitigation measures that have been proposed in the Draft EIS to protect leks and brooding habitat during critical seasons. We recommend that the Forest Service consult with FWS regarding additional mitigation measures that may be warranted considering the Candidate designation. Further, we recommend that complete avoidance of surface occupancy in critical sage-grouse habitat be considered for the proposed project, including establishment of roads, pipelines, and well pads.	Additional mitigation is discussed in the revised sage-grouse section.
010	31	UEC, WG, SUWA, WRA, WWP		WL	The road system under this analysis has been directly responsible for extirpation and reduction of charismatic mega-fauna. Remaining game and non-game wildlife populations are under constant indirect stress from extensive fragmentation and physical disturbance of individuals, populations, and their habitat. Lynx have recently started to use this area when dispersing across the west. Wolf track reports have also started to come out of this region of the state in recent years. This project includes important core, migratory, and transition habitat for TEPCS mega fauna, and this habitat and the fauna will be detrimentally impacted by the proposal. This impact needs to be drastically ameliorated.	The EIS, BE, and MIS Report for this project discuss habitat fragmentation from wells, roads, and associated activities. Refer to these documents for a discussion of this issue. The project area does not contain lynx habitat and thus there will be no effect to lynx. Wolves have never been documented within or near the project area and are rare visitors to Utah. The F&WS maintains that wolves are not an established species within this part of Utah.
010	60	UEC, WG, SUWA, WRA, WWP		WL	Migratory Bird Treaty Act The south Unit DIES overlooks substantive requirements established by the Migratory Bird Treaty Act and Executive Order 13186. There is also insufficient consideration under NEPA specific to the direct, indirect, and cumulative impacts to avian species protected under such authorities. The MBTA makes it unlawful to take, kill, or possess migratory birds, their parts, nests, or eggs. The South Unit DEIS focuses exclusively on habitat analysis while avoiding even an estimation of the amounts of direct and indirect take that most certainly would result from each of the action alternatives developed thus far.	Please see the revised migratory bird information in the FEIS and MIS Report prepared for this project.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	61	UEC, WG, SUWA, WRA, WWP		WL	EO 13186 issued in January of 2001 reinstituted the responsibilities of Federal agencies to comply with the MBTA. It is well known that many migratory bird species are currently declining across the intermountain west. We recommend the Forest conduct a rigorous evaluation using the newest data and research to minimize impacts to migratory birds and their habitat, including a focus on species on the 2002 List of Birds of Conservation Concern and species that are listed among the Partner's in Flight Priority Species.	Please see the revised migratory bird information in the FEIS and MIS Report prepared for this project.
010	62	UEC, WG, SUWA, WRA, WWP		WL	To help meet responsibilities under EO 131386 we recommend that you conduct activities outside critical breeding seasons for migratory birds, minimize temporary and long term habitat losses, and mitigate all unavoidable habitat losses. If your activities occur in the spring or summer, we recommend you conduct surveys for migratory birds to assist you in your efforts to comply with the MBTA and EO 13186. These surveys should be used to inform the NEPA documents used to support decision documents for the project.	The mitigation for migratory birds in the EIS requires surveys for FWS BCC and PIF priority species prior to surface disturbance during the breeding season (May 15th-June 30), and then restricts surface disturbance activities from occurring within a 0.1 mile buffer around nest locations or estimated nest locations. Surveys for migratory birds have been conducted within and near the project area in the past, and will continue in the future, focusing on those species listed on the BCC and the Utah PIF lists.
010	63	UEC, WG, SUWA, WRA, WWP		WL	If some portion of your mitigation includes off-site habitat enhancement, it should be in kind and either within the watershed of the impacted habitat or within the foraging range of the habitat-dependent species.	Your recommendation has been noted.
010	64	UEC, WG, SUWA, WRA, WWP		WL	To be in compliance with the language and intent of the MBTA and EO 13186, and NEPAs mandate for rigorous analysis, the environmental analysis must disclose and rigorously analyze how the proposed activities would or would not be in compliance with the MBTA and EO. The exclusive focus on habitat analysis in the South Unit DEIS is not sufficient to meet that duty.	Please see the revised migratory bird information in the FEIS.
010	65	UEC, WG, SUWA, WRA, WWP		WL	The Forest has been instructed to develop and implement, within 2 years, a MOU with the Fish and Wildlife Service that shall promote the conservation of migratory bird populations. We are not aware of any current MOUs as it appears interim MOUs have expired. Please demonstrate within the EIS for this project that such an MOU has been developed an entered into with the USFWS. Because this is an important issue that should inform the public and the decision maker, we request a copy be provided within or as an appendix to the final document.	The Ashley NF continues to evaluate potential impacts to migratory birds from proposed projects with a focus on the F&WS Service Birds of Conservation Concern as well as the Utah PIF priority species. This is done in accordance with the MOU between the F&WS and the Forest Service that was signed December 8, 2008 and which remains in effect for 5 years from the date of signing.
001	1	Central Utah Water Conservancy District	Sutherland	WR	We have reviewed the EIS and determined that the proposed action would not directly affect Central Utah Water Conservancy District facilities. None of the water courses within the area of impact feed directly into any of our reservoirs. Water courses which do directly feed the Duchesne River are well below Starvation Reservoir. At this time, there are no water quality issues which would impact our water treatment facilities as a result of the proposed action.	Noted.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	11	U.S. Department of Interior, Office of Environment	Stewart	WR	Section 2.2.5, Appendix A, and/or in Section 3.3: The following statements should be added to demonstrate the process that occurs to protect groundwater resources:"On federal leases, usable ground water resources are protected during drilling inaccordance with BLM Onshore Oil and Gas Order No. 2, which requires that allformations containing usable quality water (=10,000 mg/L total dissolved solids)be isolated and protected utilizing cement.""A site-specific analysis of ground water and its protection would be conductedduring BLM's review of an application for permit to drill. The geologist and/orhydrologist performs independent review of each APD utilizing Utah GeologicalSurvey and U.S. Geological Survey geologic and hydrologic data and maps togenerate a geologic report. The geologist and/or hydrologist identify usableground water and mineral-bearing zones that require protection. The petroleumengineer reviews the casing and cementing portions of the drilling plan to ensurethe protection of those zones identified by the geologic report. If the plannedcementing program does not adequately isolate and protect all mineral and waterbearing zones of interest then a COA will be added to the APD requiringprotection. Subsequently the operations may be inspected and/or witnessed in thefield by the BLM's petroleum engineer technicians or reviewed and addressed bythe engineers in subsequent reports of operations submitted by the operators. Ifthe zones were not adequately protected in the primary cementing operations,remedial cementing will be required in order to ensure protection of the zones.""A Forest Service interdisciplinary team reviews the surface use plan anddetermines the adequacy of reserve pit design. A closed-loop drilling system orimpermeable liner may be required if reserve pits are constructed in an area withperiodic surface water (ephemeral drainages), shallow ground water, or poroussoils over fractured bedrock. Conditions of approval are attached to the APD asnecessary.""Operators are encouraged to substitute less toxic (chromate, lead, etc.), yetequally effective chemicals, for conventional drilling products such as mud andpipe dope.""The BLM has the authority to require companies to do reasonable testing todemonstrate the mechanical integrity of the down-hole equipment if deemednecessary in accordance with 43 CFR 3162.4-2.""BLM petroleum engineer technicians inspect well sites during drilling,completion and production for technical and safety compliance.""Onshore Oil and Gas Order No. 7, Disposal of Produced Water (43 CFR 3162.5– Environment and Safety) specifies informational and procedural requirementsfor submission of an application for the disposal of produced water and thedesign, construction and maintenance requirements for disposal pits. All produced water from Federal leases must be disposed of by (1) injection into thesubsurface which is regulated by the Environmental Protection Agency (EPA) orUDOGM within the underground injection control (UIC) programs; (2) into pitswhich is regulated by BLM or UDOGM; or (3) other acceptable methodsapproved by the AO, including surface discharge under the National PollutantDischarge Elimination System (NPDES) as regulated by UDEQ. Injection ofproduced water on federal lands in Utah is regulated by Utah Administrative RuleR649-5: Underground Injection Control of Recovery Operations and Class IIInjection Wells. Injection of produced water on Indian lands in Utah isadministered by the EPA under 40 CFR Part 17.2253.""As directed by the Forest Service, containment structures are to be constructedaround all tank batteries consistent with EPA's spill prevention, control andcountermeasure (SPCC) regulations.""All spills or leakages must be reported immediately by the operator to the ForestService and the BLM in accordance with Notice to Lessees NTL-3A."	This language appears to come from IM 2010-055, specifically Attachment H. This language has been added to Section 3.6 under Mitigation – Groundwater.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
004	25	U.S. Department of Interior, Office of Environment	Stewart	WR	Page 108, line 30 - Using groundwater resources within the Upper Colorado River System may still constitute depletion if the source is hydrologically connected to surface flows. USFWS recommends the Forest Service provide further clarification as to how their groundwater sources are not connected to the Upper Colorado River System.	Additional information has been added to the FEIS regarding estimated water requirements for completion of proposed wells. No information is available regarding the surface connectivity of the these two commercial groundwater sources, as such it is assumed there is a connection and consultation with the Fish and Wildlife service will be required. By estimates this water would constitute a small depletion and not be subject to a depletion fee.
004	26	U.S. Department of Interior, Office of Environment	Stewart	WR	Page 111, line 38 - Intermittent and ephemeral drainages may be considered jurisdictional waters by the US Army Corps of Engineers. Additionally, these aquatic features serve an important role in the environment. USFWS recommends that new well pad construction avoid these areas and their associated 100-year floodplains. If avoidance is not feasible, they recommend the use of closed loop drilling in these areas.	Ephemeral channels will be buffered by a minimum distance of 50 feet. A distance of 100 feet will be maintained where feasible or will be subject to more stringent erosion control measures, including closed loop-drilling. The EIS includes mitigations for well pad and road construction relative to intermittent and ephemeral drainages. See EIS section 3.7 for details. Closed loop drilling was considered as a requirement for all proposed wells under Alternative 3 of the EIS.
006	19	State of Utah, Public Lands Policy Coordination	Harja	WR	The Utah Division of Water Quality (UDWQ) cautions that applicable water quality standards may be violated unless appropriate Best management practices (BMPs) are incorporated to minimize the erosion-sediment load to adjacent surface water during construction activities and operation of the facilities. Potential impacts from runoff during unpaved road construction or long-term operation of the oil and gas wells may include the degradation of water quality, increased quantities and intensities of peak flows, channel erosion, flooding, and geomorphic deterioration that may directly or indirectly cause an inability of surface water to maintain its designated beneficial uses.	Noted. Additional BMPs have been incorporated into the FEIS as design features and mitigation measures. In addition, the description of well pad placement has been revised to preclude placement of pads in stream corridors, including intermittent and ephemeral washes.
006	20	State of Utah, Public Lands Policy Coordination	Harja	WR	Stated in 1.7.4 "The project could increase levels of total dissolved solids (TDS), accelerate erosion, and increase salinity in the basin." The state has an active non-point source program to address TDS in the Uintah Basin. Total Maximum Daily Loads (TMDLs) have been completed and approved by the EPA on July 9, 2007, for the Duchesne River, from the town of Myton to its confluence with the Green River, antelope Creek from its confluence with the Duchesne River to its headwaters, and Lake Fork Creek for TDS impairments from the Duchesne River to its confluence with Pigeon Water Creek. The TMDL stipulates a 15% reduction in the TDS loading for this part of the Duchesne River and a 4% reduction in TDS loading in Lake Fork Creek. This TMDL has also set a site specific standard for TDS in Antelope Creek at 2,655 mg/L. Pariette Draw was listed on the 3039(d) list in 2002 for failing to meet its agricultural beneficial uses due to high TDS and boron and was also added in 2004 for failing to meet its cold water fishery use due to selenium. The Draft 2008 303(d) List for Impaired Water bodies includes Antelope Creek for not meeting its agricultural designated use due to boron exceedences and the section of Duchesne River from Randlett to Myton for not meeting its warm water fishery beneficial use due to temperature exceedances.	We recognize the efforts of the State Division of Water Quality in TMDL assessment and reduction goals for TDS loading within watersheds in the project area. We also recognize that the State holds activities within these watersheds under greater scrutiny. For this reason an array of best management practices and mitigation measures have been incorporated into this project to preserve riparian filters, maintain buffering distance to stream channels, and to contain or minimize erosion at oil pads, roads crossings, and other facilities. Details can be found in the FEIS in sections 2.2.5, 3.6.2.7 as well as Appendix B.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	21	State of Utah, Public Lands Policy Coordination	Harja	WR	Utah Division of Oil, Gas, and Mining and Utah Department of Environmental Quality both have established that no produced wastewater shall be discharged through land application in the Colorado River Basin and that decision is supported by the Colorado River Salinity control Program. The state strongly discourages the use of produced water as fugitive dust suppressant.	Recommendation is noted. Use of produced water for dust suppression on roads is not being proposed or approved as part of this project.
006	22	State of Utah, Public Lands Policy Coordination	Harja	WR	In Section 3.18.5, it states that an increase of salinity loading to surface and ground waters is "unavoidable". Disruption of the riparian zones will increase the net loading of sediment thus proper management should be executed at all locations where this disruption might occur during the exploration and development activity. The state supports the mitigation requirements identified in Section 3.6.2.7 including the additional measures that would be implemented in the riparian area long Sowers Creek and the 100 ft buffer zone around spring/wet areas. The recommended mitigation should be enhanced such that the FEIS includes a no surface occupancy (NSO) requirement within a 100-foot buffer around Sowers and Mine Hollow creek. Proper culvert and road drainage designs should also be included to reduce sediment movement into waterways.	Avoidance zones for streams, springs, and RHCA's have been incorporated into the FEIS and are described in section 3.6.2.7. These would be required as minimum buffer distances when locating site-specific facilities during the APD process. A "No Surface Occupancy" lease stipulation is not possible as the leases have already been awarded and the lease stipulations already established at that time. However, the original lease included a Lease Notice for floodplains and wetlands: "All activities within these areas may be precluded or restricted in order to comply with Executive Orders 1198 and 1190, in order to preserve and restore or enhance the natural and beneficial values served by floodplains and wetlands. Mitigation measures deemed necessary to protect these areas will be identified in the environmental analysis. These areas are to be avoided to the extent possible or special measures such as road design, well pad size and location or directional drilling may be made part of the permit authorizing the activity." It is our interpretation that minimum buffer distances for locating surface facilities are among the mitigation measures deemed necessary to protect these areas.
006	23	State of Utah, Public Lands Policy Coordination	Harja	WR	To protect the water sources within this project and the beneficial uses of these waters, the state of Utah requests the following amendments be included in the Final Environmental Assessment in Section 3.6.2.7.1. On page 221, lines 20-22, the DEIS states that water could be applied to the roads as a dust suppressant and when water application alone is insufficient to control dust, water containing magnesium chloride (MgCl) could be used. The state requests Section 3.6.2.7 be amended with a requirement that MgCl will not be used for fugitive dust suppression on any surface within 100 ft of any perennial streams, wetlands, springs, wet areas or ambient water.2. Additional language should be added to Section 3.6.2.7, "All unpaved roads and other unpaved operational areas that are used by mobile equipment shall be water sprayed and/or chemically treated to control fugitive dust. Treatment shall be of sufficient frequency and quantity to maintain the surface material in a damp/moist condition unless it is below freezing. The opacity shall not exceed 20% during all times the areas are in use."3. A requirement that except for essential and unavoidable stream crossings, a minimum of 100 ft separation will be maintained between any new road construction and existing perennial streams, i.e.. Sowers Creek and Mine Hollow.	Changes #1 and #3 have been made.Change #2 has been made but modified to clarify it would apply to roads being used by construction equipment (i.e. would not apply during production phase).

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
006	24	State of Utah, Public Lands Policy Coordination	Harja	WR	A 401 water Quality Certification permit will be required from UDWQ. A Utah Pollution Discharge Elimination System (UPDES) General Permit for Construction Dewatering, Permit No. UTG070000 for any dewatering activities that might occur during construction may be necessary. The permit requires water quality monitoring every two weeks to ensure the pumped water is meeting permit effluent limitations unless the water is managed on the construction site.	All permits required by the State will be applied for and adhered to. Citation of these can be found in sections 1.6.1, 3.6 of the FEIS, and Appendix B section 4.1
007	1	EPA	Svoboda	WR	The discussion of potential groundwater impacts in the Draft EIS is minimal, and no discussion of monitoring or mitigation is provided. A monitoring plan and program should be developed to track any groundwater impacts as drilling and production operations occur. Mitigation measures should be developed and implemented for this project to protect surface and ground water zones. EPA also recommends the Final EIS include further detail and clarification on the proposed produced water management.	The FEIS has been revised to further explain the measures taken to ensure that impacts to groundwater are prevented, following BLM IM 10-055 (Protection of Groundwater Associated with Oil and Gas Leasing, Exploration, and Development). Based on the consistent application of these measures, the USFS does not believe that a monitoring plan or other actions beyond the scope of the IM are necessary to protect groundwater resources. No further details are available concerning the produced water management.
007	2	EPA	Svoboda	WR	An attempt to identify the quality of the groundwater should be included in the Final EIS as well as the known geochemistry of the individual fresh water bearing zones. The draft document references a 1973 study with respect to local groundwater quality, stating that "current groundwater quality data was not available." We note that current groundwater quality is necessary to establish a baseline condition on which to assess possible future impacts. We recommend the Final EIS provide baseline data on the condition and quality of groundwater before drilling. This evaluation should include any evidence of hydrocarbon impacts.	The best information made available to the USFS has been incorporated into the draft, including new references to site specific water quality data. The USFS has not been able to find any data on baseline evidence of hydrocarbons, and believes that monitoring and other actions beyond the application of the guidance in BLM IM 10-055 are not necessary to protect groundwater resources.
007	3	EPA	Svoboda	WR	We recommend the Forest Service contact the Utah Department of Environmental Quality (UT DEQ) to determine if any monitoring wells exist in the area. A monitoring well grid should be installed if there is not a current well system adequate for baseline monitoring already in place	USFS believes that the adherence to BLM IM 10-055 is adequate for the protection of groundwater and that monitoring and actions beyond the scope of the IM are not necessary to protect groundwater resources.
007	4	EPA	Svoboda	WR	Characterization of the location and quality of groundwater resources present in the project area is critical to understanding potential for impact, as well as monitoring to ensure prevention of future impact. Although the Draft EIS briefly describes the major aquifers and superficial deposits, significantly more detail characterizing groundwater resources is needed and should be provided in the Final EIS. EPA requests this additional information include a stratigraphic column, the location of any wells in the project area, and chemistry and well yield data for water bearing formations. We further recommend that Drinking Water Source Protection (DWSP) zones in the project area be identified.	Per correspondence with the UTDWQ, there are no DWSPZs, public water sources, or source water assessment zones in the project area. This has been clarified in the FEIS. The best information made available to the USFS has been incorporated into the draft, including new references to four additional USGS and UDNR publications, as well as all available site-specific water quality information. In addition, the known aquifers associated with the stratigraphic column (figure 3-10) shown on page 76 of the DEIS have been described.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	5	EPA	Svoboda	WR	The protection of groundwater and surface waters are key issues to address in oil and gas development. EPA has several concerns with the proposed project with regard to protection of groundwater resources. We recommend that the characterization of the location and quality of groundwater resources be expanded beyond major aquifers and superficial deposits. Full characterization of potential groundwater features is necessary to understand the potential for impacts from the South Unit Project. The Final EIS should include a stratigraphic column that depicts the location of water bearing formations and their relationship to the production zone(s). A description of the viability of these water bearing formations as underground sources of drinking water is also needed, which should include chemistry and well yields.	The suggested discussion has been incorporated into the EIS using the limited data available.
007	6	EPA	Svoboda	WR	A list of domestic and stock wells within one mile of the project area should be included in the Final EIS as well, and any public water supply wells within 5 miles should be identified. If public water supply wells exist within the 5 mile border of the project area, then the water quality information of those supply wells should be included. The description of groundwater resources should identify the depths of the wells and what formations they are producing from.	No public water supply wells (or domestic/stock wells) are located within 5 miles of the project area.
007	7	EPA	Svoboda	WR	Additional mitigation measures beyond those suggested here may be appropriate for the South Unit Project; the Final EIS should identify all relevant and reasonable mitigation measures to protect groundwater sources, even if they are outside of the jurisdiction of the Forest Service. We recommend that the Forest Service consult the CEQ's "Draft Guidance for NEPA Mitigation and Monitoring" in developing the groundwater protection plan.	No mitigatable impacts to high quality groundwater are anticipated, due to compliance with BLM's IM 10-055 on groundwater protection. All of the mitigation measures identified for surface disturbance in the Duchense River watershed and Pariette Draw TMDLs have been added to the list of additional recommended mitigation in the FEIS.
007	8	EPA	Svoboda	WR	An analysis of the management of the fracturing fluids should be provided in the Final EIS, including the toxicity and fate of these fluids, with a focus on avoiding surface spills or leaks of these fluids from the reserve pits.	Subsurface migration of fracturing fluids and impacts to high quality groundwater would be limited. First by the lack of any identified high quality groundwater in the Project Area, and second by adherence to the guidance of BLM IM 10-055. Additional details regarding the avoidance of spills and leaks on the surface has been added to chapter 2 and to the Mitigation in Section 3.6.
007	9	EPA	Svoboda	WR	Hydraulic fracturing of any production zones near freshwater zones should not be considered. This includes fracturing production zones that are not adequately separated from freshwater aquifers with zones with low permeability that should prevent fluid and gas migration.	The potential impact of fracturing is largely unknown, with little to no mention in any regulations, and with the first studies only now being implemented by the EPA. The decision on fracturing of a specific well cannot be specified in this EIS, and will have to remain as part of the APD approval process.
007	10	EPA	Svoboda	WR	Any DWSP zones in the project area should be identified. We recommend that the Forest Service analyze the GIS information for DWSP zones, and present the results of this analysis in the Final EIS. Any municipalities with DWSP zones in the project area should be contacted	DWSP zones have been added to the discussion of water resources in Section 3.6. No municipal DWSP zones are present in the project area.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	11	EPA	Svoboda	WR	Mitigation measures should also be developed and implemented for this project to protect surface and ground water zones. Some recommended mitigation measures include: All pits should contain synthetic liners and be padded as necessary to prevent tearing or puncturing of the liner and fluid migration to the subsurface. Closed-loop drilling should be considered, particularly for sites in sensitive areas such as those near stream channels. Surface casing should be installed below all fresh water zones (underground sources of drinking water) especially if there are groundwater wells nearby. Production casing and cement should be adequate to prevent fluid movement between formations with fluids (including gas) of different quality. Forest Service should conduct an area of review for existing production wells or plugged and abandoned wells to assess whether structures possess adequate construction that prevents fluid movement within the casing/well bore annulus.	As explained above, USFS believes that the adherence to BLM IM 10-055 is adequate for the protection of groundwater and assessments and other actions beyond the scope of the IM are not necessary to protect groundwater resources.In addition, the mentioned mitigation measures are part of the language of IM 2010-055, albeit in a more generalized manner.
007	12	EPA	Svoboda	WR	The Draft EIS states that the primary source of groundwater recharge in the area is snowmelt from higher elevation. Please make clear in the Final EIS whether any well pads are located in recharge zones.	Information added to the EIS
007	13	EPA	Svoboda	WR	EPA also recommends the Final EIS include further detail and clarification on the proposed produced water management. We request the document describe specific uses planned for the 70% of produced water proposed for reuse, and explain in more certain terms where the remaining 30% of the water will be sent. The decision to avoid surface evaporation pit or well disposal may resolve many of EPA's concerns regarding potential impacts to air quality, water quality, and aquatic wildlife from on-site produced water surface impoundments.	Further information on produced water disposal has been added to Chapter 2.
007	14	EPA	Svoboda	WR	A Total Maximum Daily Load (TMDL) to address a TDS impairment was approved by EPA for the Duchesne River Watershed including Antelope Creek in 2007. There are no point sources in the Antelope Creek watershed (which includes 98% of the project area) and all loading is from nonpoint sources. Oil and gas activities are the leading contributor to the TDS loadings in the Antelope Creek watershed, likely from the many dirt roads and well pads that have been built through the years. The TMDS calls for reductions in these nonpoint source loads to ensure attainment of the water quality standard in the watershed and apportions the available load to the sources that were identified at the time the document was prepared. This project represents a significant new nonpoint source in a primarily road-less area and will result in exacerbation of the impairment that the TMDL was written to address (the development of the South Unit Project is expected to increase TDS loading through increased sedimentation and runoff.) We request that the Forest Service expand the cumulative impacts discussion for surface water quality to more fully explain how the project may contribute to TDS loadings in the Antelope Creek watershed.	Discussion of the Duchesne River and the Pariette Draw TMDLs, including the proposed site specific criteria for TDS recommended for Antelope Creek, is included in the FEIS Section 3.6.1. The Forest Service has worked with the Division of Water Quality regarding design elements and project mitigation. Recommended BMP's cited in these TMDL studies for Oil and Gas activities have been incorporated into the required mitigation measures for the project. Division of Water quality recommendations regarding riparian habitat protection, erosion control, dust abatement, and stream crossings have also been incorporated into these mitigation measures, and as such are consistent with TMDL reduction strategies for the watersheds.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	15	EPA	Svoboda	WR	EPA is pleased with the selection of Alternative 4 as the Preferred Alternative due to its reduced surface disturbance relative to the Operator's Proposed Alternative. However, we recommend that additional steps be taken to further minimize erosion and sedimentation for watershed protection. First, we recommend that the Forest Service reconsider a cap on acres of surface disturbance, which was not carried into the Draft EIS for detailed analysis. Placing a limit on the maximum number of acres of surface disturbance allowed in the project area at any one time can significantly limit TDS loading by increasing interim reclamation efforts and decreasing the amount of disturbed soils. Second, we recommend that phased drilling be considered for the proposed action, which will also effectively reduce the amount of surface disturbance present at any time. Finally, EPA recommends s that the Forest Service considers further reducing construction of roads or well pads in drainages.	The Preferred Alternative (Alt. 4) is designed to minimize surface disturbance. The reason this was not brought forth for detailed analysis is described in Section 2.3.2 of the FEIS. The EIS has been revised to reflect that no well pads or roads (other than essential crossings) would be placed in drainages with defined bed and banks. An array of best management practices and mitigation measures have been incorporated into this project to preserve riparian filters, maintain buffering distance to stream channels, and to contain or minimize erosion at oil pads, roads crossings, and other facilities.
007	16	EPA	Svoboda	WR	Although we are pleased that the Preferred Alternative reduces the miles of stream disturbance, we are very concerned that 5.3 acres of stream disturbance are still anticipated for the project. To reduce TDS loading, directional drilling should be used to access mineral resources within drainages wherever possible, and roads and well pads should be sited outside of these sensitive zones. We recommend coordination with the U.S. Army Corps of Engineers (USACE) if a Clean Water Act (CWA) Section 404 permit will be required for discharge of dredged or fill material into Waters of the U.S.	Multiple pad wells and the use of directional drilling are anticipated in the action alternatives. Mitigation measures incorporated into the FEIS include 150' buffer from the high waterline of Sowers creek, a 50' minimum buffer from the active channel and cut banks of ephemeral channels, 100' buffer from springs, seeps and riparian vegetation. Siting of oil pads, compressor stations and other facilities would avoid these areas. Roads crossing these buffers would be limited to perpendicular or near perpendicular crossing and subject to erosion control measures.By law, impacts to all jurisdictional waters would be avoided, minimized, and/or mitigated during the site-specific permitting process.
007	17	EPA	Svoboda	WR	EPA recommends the Forest Service implement a comprehensive water monitoring plan to ensure the BMPs are successfully mitigating the impacts from increased sedimentation. At a minimum, we recommend that the Forest Service establish a monitoring program in Antelope Creek and Sowers Creek. EPA looks forward to the Forest Service establishing an effective monitoring program and utilizing the results from those monitoring efforts to direct reclamation resources and efforts.	The FEIS has been revised to further explain the measures taken to ensure that impacts to groundwater are prevented, following BLM IM 10-055 (Protection of Groundwater Associated with Oil and Gas Leasing, Exploration, and Development). Based on the consistent application of these measures, the USFS does not believe that a monitoring plan or other actions beyond the scope of the IM are necessary to protect groundwater resources.
007	18	EPA	Svoboda	WR	It is best to involve a system of BMPs that targets each stage of the erosion process to ensure success from construction activities. The most efficient approach involves minimizing the potential sources of sediment from the outset. This means limiting the extent and duration of land disturbance to the minimum needed, and protecting surfaces once they are exposed. BMPs should also involve controlling the amount of runoff and its ability to carry sediment by diverting incoming flows and impending internally generated flows. In addition, BMPs should include retaining sediment that is picked up on the project site through the use of sediment-capturing devices. On most sites successful erosion and sedimentation control requires a combination of structural and vegetative practices. Finally, BMPs are best performed using advance planning, good scheduling and maintenance.	An array of best management practices and mitigation measures have been incorporated into this project to control and minimize erosion from the proposed oil and gas development alternatives. Details can be found in the FEIS in sections 2.2.5, 3.6.2 as well as Appendix B.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
007	19	EPA	Svoboda	WR	It is implied in the Draft EIS that water needed for development activities will be obtained from the Petroglyph Operating Company Water plant and/or the Arcadia Feedlot. The Forest Service therefore concludes that impacts to surface or groundwater in the project area due to freshwater consumption would be minimal; however, more detail regarding water use is needed to support this conclusion. Please include additional information regarding freshwater sources, estimated consumption, and water transport plans for the proposed project. A map showing where freshwater sources would be obtained and how they would be transported to the project area would be helpful	Additional information regarding freshwater use, projected quantities and sources are provided in sections 3.6.2 and 3.19.5 of the FEIS. Details of the water sources (township Ranges and Sections) are located in Appendix A in the surface use plan, Sec 5 p A-16. And section 7E (p A-17) lists the sites for disposal of production water.
007	22	EPA	Svoboda	WR	We note that the Forest Service should minimize impacts associated with crossing of drainages in accordance with EO 11990, even when Clean Water Act permitting is not required. Estimated stream crossings should be included in the Final EIS, as well as proposed mitigation measures for any unavoidable impacts.	Stream crossings would be the minimum necessary for the approved alternative. The FEIS describes crossings for new roads would be designed so they would not cause headcutting, siltation, or the accumulation of debris in the channel. Plans for crossings would be submitted and subject to Forest Service engineer approval before construction may begin. Other permit requirements/coordination required for crossings may include: U.S. Army Corps of Engineers 404 permitting and State of Utah 401 permitting.
010	8	UEC, WG, SUWA, WRA, WWP		WR	Under the Clean Water Act, the Forest Service must establish that its actions are consistent with Utah water quality standards. It must also abide by its substantive duty under NFMA to protect water resources. 33 U.S.C 1313.	Noted. Language has been added to the FEIS.
010	9	UEC, WG, SUWA, WRA, WWP		WR	The Western Uinta Basin Oil and Gas ROD makes clear that protecting riparian areas from the impacts of oil and gas development is critical to “maintain water quality and stream bank stability and to provide wildlife [habitat] and shade for fisheries.” ROD at 6. The ROD places an NSO stipulation on riparian areas of great than 40 acres and states that Forest Service intends “to protect areas smaller than 40 acres to the same degree.” ROD at 6. The ROD also recognizes the adverse impact to water quality that result from road building and states that roads “would not be allowed in areas where the likely result would be unacceptable degradation of water quality, fisheries habitat, etc.” ROD at 3. This provision when coupled with the Reform Act requirements, discussed in detail elsewhere, also underscore the need to prohibit development in and around steam beds. Importantly, the Western Uinta Basin EIS defines “riparian” to include terrestrial and aquatic ecosystems “in a position to directly influence water quality and water resources, whether or not free water is available. This would include all lands in the active flood channel and lands immediately upslope of stream banks” Including areas associated with “intermittent or permanent streams.”	The EIS has been revised to reflect that no well pads or roads (other than essential crossings) would be placed in drainages with defined bed and banks. In addition, drainages with distinctive riparian (i.e. wetland) vegetation would be avoided by a margin of at least 50 ft. The operator would be required to avoid and minimize impacts to wetlands and waters of the US during the site-specific Section 404 permitting process.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	10	UEC, WG, SUWA, WRA, WWP		WR	All the alternatives (2-4) that allow development to proceed in the project area violate the Clean Water Act and run afoul of the Forest Service's obligation to ensure that the activities it approves will not cause or contribute to a violation of water quality standards. See also Western Uinta Basin ROD at 11 ("if, at the time a drilling proposal is submitted, the environmental analysis concludes that cumulative effects associated with the proposal and other resources activities in the area will exceed state water quality standards or forest plan standards, off-site mitigation may be required or the proposal denied until the standards can be met."	A discussion of major transport pathways associated with water quality impairments in Antelope Creek and Pariette Draw has been added to the FEIS. Further, a site-specific standard for TDS for Antelope Creek is currently under revision by the State of Utah. This is also included in the discussion of sources of TDS in the FEIS.~~.~~
010	11	UEC, WG, SUWA, WRA, WWP		WR	Currently, all waters in the project area that have been monitored fail to meet their beneficial uses. In addition, the Forest Service lacks adequate monitoring data to assess the remaining waters. This means, first, that the agency has failed its NEPA obligations to take a hard look that the potential impacts of the proposed project and alternative actions on surface waters and water quality. Second, it is plain that existing development in the area is already causing or contributing to a violation of state water quality standards, including the anti-degradation policy. Moreover, particularly as currently applied "best management practices" have failed to protect these waters, the Forest Service cannot allow any development to occur in the project area until the agency establishes that development will not contribute to existing violations. The Forest Service certainly has not done so in the South Unit DEIS.	Comment noted. Adequate monitoring data are available from UDEQ for Antelope Creek, Sowers Creek, and Duchesne River to assess current water quality conditions. These data are summarized in the recently completed TMDL for the Duchesne River watershed. These data are incorporated into the Final EIS in Section 3.6.1.1 Additional discussion on the primary sources of salinity and boron in the watershed have been added to Section 3.6.1.1 of the FEIS.
010	12	UEC, WG, SUWA, WRA, WWP		WR	That water quality in the project area is impaired underscores the need for the Forest Service to enforce its previous prohibition on surface occupancy in stream beds and to institute a buffer around these areas. The poor water quality in the project area also means that the Forest Service must, under the WUB ROD, the Forest Plan, and its statutory duties, prohibit road building in stream corridors.	Wording has been expanded in the FEIS regarding stream buffers to cite 150' buffer from the high waterline of Sowers creek or 100 year flood plain whichever is greater, a 50' minimum buffer from the active channel and cut banks of ephemeral channels. A 100' buffer from springs, seeps and riparian vegetation. Siting of oil pads, compressor stations and other facilities would avoid these areas. New road construction would avoid these areas except for essential crossings limited to perpendicular or near perpendicular crossings to minimize disturbance and would be subject to additional erosion control measures.Recommended BMP's cited in Pariette and Duchesne River TMDL studies for Oil and Gas activities have been incorporated into the required mitigation measures for the project. Division of Water quality recommendations regarding riparian habitat protection, erosion control, dust abatement, and stream crossings have also been incorporated into these mitigation measures, and as such are consistent with TMDL reduction strategies for the watersheds.
010	13	UEC, WG, SUWA, WRA, WWP		WR	-As warranted by the poor water quality in the project area, the Forest Service has failed to consider an alternative to the proposed development that will ensure compliance with water quality standards. Such an alternative would prohibit road building and well pad construction in and around all stream beds and corridors.	The EIS has been revised to reflect that no well pads or roads (other than essential crossings) would be placed in drainages with defined bed and banks.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	14	UEC, WG, SUWA, WRA, WWP		WR	-The Forest Service has failed to establish how any development in the project area will comply with Utah's narrative standard, particularly where the agency admits that accidental spills will occur.	The project would include the implementation of a project Spill Prevention, Control, and Countermeasure Plan (SPCCP).
010	15	UEC, WG, SUWA, WRA, WWP		WR	-The South Unit DEIS completely fails to address whether development in the project area will add selenium, a toxic water pollutant, to Utah's waters and to analyze the environmental impacts of such a discharge.	A discussion on selenium transport pathways and their relationship to oil and gas development has been added to Sections 3.6.1. and 3.6.2 of the FEIS
010	16	UEC, WG, SUWA, WRA, WWP		WR	-The Forest Service has not shown how development in the project area will comply with State water quality standards, including the anti-degradation policy.	Additional summary of impairments and TMDL results for the Duchesne River watershed and Pariette Draw have been added to Section 3.6.1 of the FEIS. An analysis of water quality impacts associated with oil and gas development have been included in Section 3.6.2
010	17	UEC, WG, SUWA, WRA, WWP		WR	-The Forest Service has failed to discuss the existing TMDL for Antelope Creek and how development in the project area will comply with the provisions of that document.	A discussion of the Duchesne River watershed TMDL and the Pariette Draw TMDL, including the proposed site specific criteria for TDS for Antelope Creek, is included in Section 3.6.1 of the Final EIS. There are no specific load allocations identified for Antelope Creek
010	18	UEC, WG, SUWA, WRA, WWP		WR	-The analysis of sedimentation in the South Unit DEIS does not include contribution from slope failures, and is only calculated based on average tons/acre soil loss from various soil types	Section 3.2 and section 3.5.2 of the EIS include a discussion of potential impacts of sedimentation. As noted, the actual occurrence, extent, and degree of impacts to soil resources depend on site specific details and the specific alternatives being proposed. The expected degree and frequency of impacts on soils cannot be determined until the site-specific APD stage of permitting approval. An estimate of occurrence of slope failure is not possible at this stage of analysis. Impacts from slope failure is addressed through avoidance, mitigation, and best management practices during approval of site-specific proposals. Stipulations for the Berry oil and gas leases designate No Surface Occupancy (NSO) for slopes exceeding 35% and NSO for lands with geologic hazards or unstable soils. Further mitigations/best management practices regarding the citing and design of roads, pipelines, and facilities are incorporated into the FEIS to further reduce risk of slope failure.
010	19	UEC, WG, SUWA, WRA, WWP		WR	-The analysis in the South Unit DEIS by high-level watershed is not detailed enough to show specifically the source of sediments and other pollutants, including selenium. The Forest Service must run a detailed quantitative analysis by smaller watersheds that are directly tied to landslide or erosion prone slopes in order to accurately calculate sediment contribution and impacts to specific water bodies.	A regression analysis of neighboring Pariette Draw was used to assess change in water quality (including sediments, selenium, boron, and dissolved solids) associated with oil and gas development between the years 1993 and 2007. The results are included in Seciton 3.6.2 of the FEIS.

Submittal #	Comment #	Organization	Last Name	Resource Category	Comment Text	Response to Comment
010	20	UEC, WG, SUWA, WRA, WWP		WR	-The South Unit DEIS must undertake a detailed cumulative effects analysis that analyzes all human-induced erosion sources in addition to the proposed development, such as existing energy development, grazing, and logging.	Existing and potential erosion sources were considered in cumulative effects analysis for soil and water resources and in design of mitigation measures (sections 3.5, 3.6) and the Resource Specialist Reports). TMDL studies have also been conducted for the Antelope and Pariette watersheds by the State of Utah Division of Water Quality. These were watershed-wide assessment of potential point and nonpoint pollutant sources, both natural and human induced. In the South Unit EIS these published TMDL studies were referenced and considered (in sections 3.6.1.1 and the Specialist Resource Report) when analyzing existing conditions of potential effects to water quality.
010	21	UEC, WG, SUWA, WRA, WWP		WR	-The mapping of landslides in the South Unit DEIS is inadequate. The South Unit DEIS needs to utilize the most current soil types and mapping information.	The USFS has relied on the best available information on landslides and soil types. The commenter has not provided more up to date information or evidence that the information included is inadequate.
010	22	UEC, WG, SUWA, WRA, WWP		WR	-the South Unit DEIS needs to quantify the engineering and construction costs associated with complying with State water quality standards and reducing the risk of landslides and slope failures to a minimum level.	Stipulations, mitigation, and best management practices will be incorporated into the decision based on resource protection, Forest Plan guidance, and the policies and regulations governing oil and gas development. Quantification of such costs is not within the scope of the decision.
010	23	UEC, WG, SUWA, WRA, WWP		WR	The South Unit DEIS fails to adequately consider the impact of ruptures, spills, and leaks from pipelines and well pad areas [to water quality].	The Forest Service requires the proponent to have spill prevention control countermeasure plan. BLM NTL-3A, referenced in section 3.6. which references potential for spills from produced water and petroleum.
010	24	UEC, WG, SUWA, WRA, WWP		WR	The Forest Service did not analyze the impact on water quality of the air pollution generated by the proposed project and alternatives.	Sections 3.2.1.7 and 3.2.2 of the FEIS offers discussion of air pollution and potential effects to water quality of lakes with low acid neutralizing capacity.
010	25	UEC, WG, SUWA, WRA, WWP		WR	The Forest Service did not accurately portray or analyze the impacts of development in the project area on water quality because the agency would allow for development and road to be constructed in riparian areas.	Wording has been expanded in the FEIS regarding stream buffers (a 150' buffer from the high waterline of Sowers creek or 100 year flood plain whichever is greater, a 50' minimum buffer from the active channel and cut banks of ephemeral channels, and a 100' buffer from springs, seeps and riparian vegetation). Siting of well pads, compressor stations and other facilities would avoid these areas. New road construction would avoid these areas except for essential crossings limited to perpendicular or near perpendicular crossings to minimize disturbance and would be subject to additional erosion control measures.